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TURCENI ENERGY COMPLEX – VALUATION REPORT

October 2005

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It was prepared by Deloitte & Touche Romania as part of the Emerging Markets Group, Ltd. led consortium operating under the USAID Romania PRIDE project.

EMERGING MARKETS GROUP

TURCENI ENERGY COMPLEX – VALUATION REPORT

ENTERPRISE VALUATION OF TURCENI ENERGY COMPLEX

AS OF DECEMBER 31ST, 2004

Submitted by:

PRIDE Project
Deloitte & Touche Romania as part of the Emerging Markets Group, Ltd. led consortium operating under the USAID Romania PRIDE project

Submitted to:

USAID Bucharest for review and approval
MEC - Office of State Ownership and Privatization in Industry

Contract No.:
PCE-I-00-97-00016-00, TASK ORDER 811

Disclaimer

The valuation analysis contained in this report is intended to be one of several factors considered by the Ministry of Economy and Commerce, as sole shareholder of the Turceni Energy Complex, in the decision-making process regarding the potential sale of a majority interest in the Complex in the privatization process of the energy sector in Romania.

This report is not to be used for any other purpose or distributed to third parties without the express knowledge and prior written consent of Deloitte. Furthermore, the result of our valuation analysis does not constitute a fairness opinion or investment advice and should not be interpreted as such.

In addition, this report is subject to the following general assumptions and limiting conditions:

- The Company valuation was based on the internationally recognized and used valuation principles;

- Our work does not intend to provide assurance on the value of the business or on the achievability of the projections or on the assumptions underlying such statements, nor does it provide assurance that we would become aware of significant matters that might be disclosed by more extensive procedures. There are usually differences between projected and actual results, because events and circumstances frequently do not occur as expected and those differences, if any, may be material;

- The Company's Management was responsible for representations about its plans and expectations and for the disclosure of significant information, which might affect the ultimate realization of the projected results and therefore assumes responsibility for the Company's projections. Consequently and given the above stated limitations, we do not express any opinion on the achievability of the projections by the Management;

- Extraordinary future events that might affect the Company's operations were not taken into consideration, except for the ones included in this report, if any;

- No responsibility is taken for changes in market conditions and no obligation is assumed to revise this report to reflect events or conditions, which occur subsequent to the date thereof;

- Information furnished by Management and other third parties, upon which this valuation analysis is based in its entirety, is believed to be reliable, but has not been verified except as set forth in this report. No warranty is given as to the accuracy of such information;

- No material information other than those incorporated within the financial projections that could influence the Company's future prospects was publicly available at the date of completion of this valuation work;

- The Management has not informed us of any tax, legal or other issues and disputes that could influence the future prospects of the Company pending to the date of completion of this valuation work except for the ones included in this report, if any;

- It is assumed that all required licenses, certificates of occupancy, consents, or other legislative or administrative authority from any government or private entity or organization that are relevant to the financial information and/or forecasts on which the value estimates contained in this report are based have been or can readily be obtained or renewed for any use;

- Full compliance with all applicable laws and regulations is assumed, unless otherwise stated;
- We have not carried out any audit or review engagement procedures in relation to the historical financial statements of the Company. Consequently, no assurance on the financial statements is expressed;
- Responsible ownership and competent management are assumed;
- The projected cash flows are presented in real values and are discounted by using real discount rates;
- The Company will continue to operate under the current top management structure;
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- No direct discussion has taken place with technical experts assigned on the PRIDE project, therefore references to investments and consequential capital expenditure are solely based on the information received from Management and discussed with RAEF another subcontractor to Emerging Markets Group to this project;
- We were dependent upon Management, for information updates during the valuation analysis, who did not in all cases provide the updates requested. Therefore, some historic data alluded to in the report is not comprehensive to the valuation date;
- The information contained in Appendix 5 has not been updated to reflect events that occurred after 31 December 2004, which is the date of valuation;

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1. Executive Summary

1.1 Engagement Purpose

The objective of this valuation analysis is to assist the Turceni Energy Complex (hereafter referred to as "**the Company**", "**TEC**" or "**the Complex**") in establishing a range of fair market values for a 100 percent interest in its owners' equity as at 31 December 2004.

This valuation analysis is intended to be one of several factors considered by the Ministry of Economy and Commerce, as sole shareholder of the Turceni Energy Complex, in the decision-making process regarding the potential sale of an interest in the Complex within the privatization process of the energy sector in Romania. Accordingly, our work product is not to be used for any other purpose or distributed to third parties without the express knowledge and written consent of Deloitte. Furthermore, the result of our valuation consulting services does not constitute a fairness opinion or investment advice and should not be interpreted as such.

1.2 Scope of Work and Information Sources

This valuation report has been prepared during September 2004 – July 2005 based on the following:

- Draft Information Memorandum as initially received in September 2004 from EMG;
- Trial balances of TEC as of April 1st, 2004 and December 31st, 2004
- Audited financial statements of the Complex as of April 1st, 2004 and December 31st, 2004;
- Forecasts for the main operational assumptions (power production, fuel, water, electricity consumption), as provided by TEC management;
- Investment plan for the rehabilitation of 3 units and installation of 4 FGD Units and other necessary modernizations for the extension and well functioning of the power plant beyond 2010;
- Investment plan for increase of coal production capacity at Jilt mines;
- Review of recent studies regarding closure of thermal power plants, investment capacity of TPP, comparable transactions in CEE;
- Discussions and visits at Turceni TPP, MEC, RAEF, USAID, EMG;

1.3 Main Characteristics of the Romanian Market

Romania entered into the negotiations for accession to the European Union in February 2000 and closed all the negotiation chapters with the EU in November 2004. In April 2005, Romania signed the Accession Treaty in Luxembourg with the scheduled accession date set for January 1st, 2007.

In November 2004, Fitch assigned "investment grade" rating to Romania ("BBB-" with a "stable" outlook).

The liberalization of the Romanian electricity market has been initiated in early 2000 and guided by the principles of the EU Directives 96/92/EC and, subsequently, 2003/54/EC concerning common rules for the Internal Market in Electricity.

The Romanian regulatory authority for electricity and heat generation (ANRE) was set up in 1998, and has been tasked with creating and implementing an appropriate regulatory system to ensure the proper functioning of the electricity and heat markets.

In January 2005, the opening degree has reached 55%, with all companies exceeding 1 GWh of electricity consumed in 2004 being declared eligible consumers of electricity. In July 2007, 100% of industrial consumers became eligible and starting with July 1st 2007 the Romanian electricity market will be fully open.

1.4 Brief Description of the Business

The Turceni Energy Complex was set up in April 2004 through the merger of the "Electrocentrale Turceni" thermal power plant and three lignite mining exploitations – the Jilt Nord and Jilt Sud open pits and Dragotesti underground mine.

The core activity of the Turceni Energy Complex is electricity generation. Its ancillary activities are: heat generation and the supply of system services.

The Turceni TPP is the largest in Romania with an installed capacity of 2310 MW (7 x 330 MW installed power) and a current operational capacity of about 1260 MW. The production units have been commissioned during a period from July 1978 (unit 1) to November 1987 (unit 7).

1.5 Valuation Results

According to the PRIDE project requirements, as reflected in the subcontract concluded by Deloitte & Touche Romania with Emerging Markets Group, a comprehensive valuation exercise of Turceni Energy Complex should be performed. Three forms of valuation should be performed: Net Asset Value, Comparative Company Analysis and Discounted Cash Flow. Furthermore 5 scenario runs of the discounted cash flows model should be presented.

1.5.1 Discounted Cash Flows Approach

In the application of the Discounted Cash Flows Approach we have considered 5 alternative investment scenarios, the electricity selling price of USD45/MWh and a discount rate of 13%, the exchange rate for EUR is 40,00 ROL and for USD is 30,000 ROL

Due to the uncertainty concerning the future Romanian Energy Market we have agreed with the Client and with TEC management to present scenarios where future production capacity of TEC varies by proposing combinations of power production units (the group formed of a steam boiler, steam turbine and electricity generator) and flue gas desulphurisation units (the device which, attached to a power production units enables it to meet minimum environmental requirements necessary to be alowed to function past the year 2010).

Scenario 1, "Full investment" is the base scenario as it is supported by both TEC management and Government. The scenario forecasts that 3 additional power generating units will undergo techonological rehabilitation (one unit has been recently put in function after such a process) and that 4 FGD units will be attached to all units, resulting a nominal power generation capacity of 1320 MW. Substantial investment in the development of the mining exploitation and in environment protection will be necessary in order to ensure the functioning of the plant for the next 15 years (the average techical life of the rehabilitated units).

Scenarios 2 and 3, "Medium investment" forecast the continuation of the activity with only 2 rehabilitated units with corresponding FGD units resulting a power generation capacity of 660MW. Environmental investment is also reduced due to the reduced activity. While Scenario 2 supposes some investment in the increase of coal output of mines associated with TEC, Scenario 3 forecasts a greater dependency on external lignite suppliers.

Scenario 4 "Reduced investment" is based on a future power production capacity of 990MW obtained by attaching FGD units to 3 of the existing power produciton units without performing any additionnal rehabilitation work.

Scenaro 5 "No investment" forecasts the closure of TEC in the year 2010 since no environmental investments necessary to comply with regulations is performed.

Scenario number	Scenario name	No of FGD's	Number of functionning Units (after 2011)	No of Rehabilitated Units	Indicative Value (USD, rounded)
1	**Full investment**	**4**	**4**	**4**	**20,909,894**
2	Medium investment with increase of mining capacity	2	2	2	2,460,804
3	Medium investment without increase of mining capacity	2	2	2	6,712,843
4	Reduced investment	3	3	2	142,205,632
5	No investment	0	0	1	217,820,757

The results of the DCF approach show only marginal profitability of the investment in TEC under the assumptions used for building the financial forecasts.

The implementation of environment related investments has a heavy impact on the value of the Company, given the current market conditions, and therefore Scenario 5 appears as the most attractive solution for the use of the existing assets.

The very small value resulting from the application of scenario 2 and 3 demonstrate the need of restructuing the asset base of TEC if such a future path will be chosen by the investor, measure which could, potentially improve dramatically the profitability of the business and TEC future cash flows.

According to TEC management Scenarios 4 and 5 are represent for technical and strategy reasons only theoretical possibilities. Given the uncertainty of the achievability of these scenarios the discount rate applied to the model should have been increased. For comparability purposes, when presenting the value of the equity of TEC under Scenarios 4 and 5 we retained the same discount level.

The relatively small value (approximately EUR 21 million) of the base Scenario ("Full investment") emphasizes the senzitivity of the investment to future market developments and the need to incorporate in the selling price the additionnal costs generated by environment protection measures. In order to test this sensitivity we have built the following alternative scenarios:

Scenario number	Scenario name	Average electricity sales (GWh/year)	Selling price of electricity (USD/GWh)	Indicative Value (USD, rounded)
1	**Optimistic output, conservative selling price**	**7,756**	**45**	**20,909,894**
1a	Conservative output, conservative selling price	5,672	45	0 *)
1b	Conservative output, optimistic selling price	5,672	50	16,524,331
1c	Optimistic output, optimistic selling price	7,756	50	205,693,113

*) the sum of discounted cash flows over the forecast period is negative USD 170 million

In our opinon, Scenario 1 provides a value closest to the market value of TEC at the date of our valuation and considering the assumptions provided by TEC management,

If the future market conditions will prevent TEC sales to raise to the level forecasted by the management and if the selling price will not increase the value of the Company could be significantly impaired as described by Scenario 1 a.

Similarly if TEC sales will raise to the level forecasted by the managemnt and the market conditions will permit the increase of the selling price above the forecasted levels the value of the Company might improve towards the value described by Scenario 1c.

1.5.2 Adjusted Net Assets Approach

The Adjusted Net Assets valuation of Turceni Energy Complex was performed based on the Financial Statements issued at December 31st, 2004 in accordance with the International Financial Reporting Standards.

The adjustments were based on the findings of the financial analysis of the Energy Complex performed during June 2005 for December 31st, 2004 and resulted in an **Adjusted Net Assets** value of **USD 487,9 million.**

This resulting value is highly depending on the value of fixed assets owned by TEC. Being highly specialized and virtually impossible to be used outside the Company it is difficult to assess their market value.

In our opinion the value resulting from the application of this method is not representative for the market value of the Company.

1.5.3 Market-based Approach

Fair market value of the Complex was estimated by using the Private Company Transaction method. Five transactions were reviewed - thermal power plants privatized in the Central and Eastern Europe in the period 1998 – 2004. The results obtained were as follows:

Market Value Ratio	Ratio	Parameter (USD)	Indicated Value (USD, rounded)
December 31, 2004 Revenues	1.02	209,380,188	213,416,000
December 31, 2004 EBIT	11,70	11,099,855	129,754,000

This result should be cautiously read since significant investments are needed in order to comply with EU environment directives beyond 2010. If those investments would be taken into consideration with a present value ranging between 200 and 430 million USD then, the 100% equity value of TPP may result in a negative amount.

Moreover, the guideline companies had operated prior to privatization on markets which adopted the "single-buyer" market model. Therefore, there is a high probability that these companies were sold with PPAs (power purchase agreements) concluded with a state owned-entity at a price sufficient to ensure positive cash flows over a reasonable period of time (+10 years), which will most probably not be the case for TEC.

The significant difference between revenue-based value and EBIT-based value highlights the relatively low efficiency of TEC operational model. Taking into account that the Complex is currently operating 6 units (1 is closed for rehabilitation) but is selling electricity as for 4 units fully loaded, the difference can be considered normal, as it reflects the poor operational efficiency of the assets employed for electricity generation.

Due to the uncertainities relating to the conditions under which the studied transactions took place the value resulting from the application of the market based approach is not representative for the market value of TEC.

2. Glossary of terms

In this report the terms in the left column has the meaning ascribed in the right column, unless the context requires otherwise.

ANRM	National Agency for Mineral Resources
CEE	Central and Eastern Europe
CNLO	National Company of Lignite Oltenia
DCF	Discounted & Cash Flow
EBIT	Earnings Before Interest and Tax
EBITDA	Earnings Before Interest, Tax, Depreciation and Amortisation
EMG	Emerging Markets Group
EU	European Union
FDG	Flue Gas Desulphurization
IBRD	International Bank for Reconstruction and Development
JBIC loan	Japan Bank for International Cooperation
Kcal/kg	Kilocalories/Kilogram
Management	The Management of Turceni Energy Complex
MW	MegaWatt
NAV	Net Asset Value
NOx	Nitrogen Oxides
OPSPI	Office of State Ownership and Privatization in Industry
PPA	Power Purchase Agreement
PRIDE	Privatization, Investment, and Development of Energy Program
RAEF	Romanian American Enterprise Fund
SO2	Sulfur Dioxide
TEC	Turceni Energy Complex
TPP	Thermal Power Plant
UCTE	Union for the Co-ordination of Transmission of Electricity

3. Introduction

This report was commissioned by Emerging Markets Group ("**the Client**") as part of the PRIDE USAID funded project of assistance for a transparent and equitable privatization of the Turceni Energy Complex. The objective of the valuation analysis was to assist the Turceni Energy Complex in establishing a range of fair market values for a 100.00 percent interest in its owners' equity as at 31 December 2004, assuming that the assets are housed in a debt free entity.

Section 4 below contains important information regarding the limitations of this report and should be read and taken into account by recipients of this report.

Section 5 describes a number of issues that form part of the valuation context. These include the basis of the valuation analysis (including some major assumptions and issues taken into consideration), capital structure, important information in relation to both the electricity production and coal mine facilities, important aspects of the investment and development programmes for the Complex as well as some environmental issues.

Three different valuation approaches are discussed in sections 6, 7 and 8. These are the asset-based approach, the market approach and the income approach.

4. Scope of Work and Information Sources

This valuation report has been prepared during September 2004 – July 2005 based on the following:

- Draft Information Memorandum as initially received in September 2004 from EMG;
- Trial balances of TEC as of April 1st, 2004 and December 31st, 2004
- Audited financial statements of the Complex as of April 1st, 2004 and December 31st, 2004;
- Forecasts for the main operational assumptions (power production, fuel, water, electricity consumption), as provided by TEC management;
- Investment plan for the rehabilitation of 3 units and installation of 4 FGD Units and other necessary modernizations for the extension and well functioning of the power plant beyond 2010;
- Investment plan for increase of coal production capacity at Jilt mines;
- Review of recent studies regarding closure of thermal power plants, investment capacity of TPP, comparable transactions in CEE;
- Discussions and visits at Turceni TPP, MEC, RAEF, USAID, EMG;

5. Valuation process

Introduction

This section sets out a number of issues that forms part of the valuation context. These include the basis of the valuation (including some major assumptions and issues taken into consideration), capital structure, important information in relation to both the electricity production and coal mine facilities, important aspects of the investment and development programmes for the Complex as well as some environmental issues.

Valuation Basis

This valuation report has been prepared during September 2004 – June 2005 based on the following:

- Draft Information Memorandum as initially received during September from EMG;
- Trial balances of TEC as of December 31st, 2004;
- Forecasts by the Management of the main operational assumptions, including, but not limited to power production, fuel consumption and prices, electricity consumption;
- Investment plan of TEC for the rehabilitation of 3 units and installation of 4 FGD Units and other necessary modernizations for the extension and efficient functioning of the power plant beyond 2010;
- Investment plan of TEC for an increase in the coal production capacity at Jilt mines (forming part of the Complex);
- Discussion with MEC and TEC representatives regarding the closure of thermal power plants spun off from Termoelectrica (the former national coal-based electricity and heat producer), investment requirements of TPP and comparable disposals in CEE;
- Information obtained during discussions with and/or visits to Management, Turceni TPP, MEC, RAEF, USAID and EMG;

Valuation Scenarios

Based on the above information, five valuation scenarios were devised. The scenarios differ in terms of units modernized, number of FGDs installed and whether an investment plan for the coalmines is implemented. The differentiating features of each of the five scenarios are briefly described below:

1. Scenario no. 1 – "full investment" is based upon the following assumptions:
    - Units modernized: Units no. 3, 4, 5 and 6;
    - FGDs installed: for Units no. 3,4,5, and 6;
    - Investment plan for coalmines: Yes.

2. Scenario no. 2 – "medium investment with coalmines"
    - Units modernized: Units no. 4 and 5;
    - FGCs installed: for Units no. 4 and 5;
    - Investment plan for coalmines: Yes.
3. Scenario no. 3 – "medium investment without coalmines"
    - Units modernized: Units no. 4 and 5;
    - FGDs installed: for Units no. 4 and 5;
    - Investment plan for coalmines: No.
4. Scenario no. 4 – "reduced investment"
    - Units modernized: Unit no. 4,5;
    - FGDs installed: Units no. 4,5 and 6;
    - Investment plan for coalmines carried out: No.
5. Scenario no. 5 – "no investment"
    - Units modernized: Unit no. 4;
    - FGDs installed: None;
    - Investment plan for coalmines: No.

For the base scenario (i.e. the scenario underlying all of the scenarios), following main assumptions have been taken into account:

- One rehabilitated electicity production unit has a life cycle of 15 years after commissioning.
- Given the technology used, it is compulsory to install FGD units in order to comply with EU environmental requirements by 2011.
- Specific consumption of coal for existing, non-modernized units is greater than in case of new units and compared with catalog numbers.
- Since no study on the Romanian electricity market, and more specifically future electricity selling prices, has been made available during the valuation analysis process, the current levels of electricity selling prices have been considered for base scenario during the entire forecast period
- The valuation analysis is based on the assumption of a debt free entity. As a result, the ranges of equity value is equal to the Company's enterprise value.

Except for the full investment plan scenario, technical feasibility has not been confirmed by independent technical experts. However, the alternative scenarios were presented by us to the management and to MEC without being formally rejected or accepted.

One of the main constraints to considering the feasibility of those scenarios is represented by the advanced stage of negotiation regarding the JBIC loan for the installation of the 4 FGD units at TPP. During the valuation process it became apparent that the JBIC loan would be implemented, therefore the full investment plan scenario has been adopted as the base scenario. In addition, the Energy Roadmap approved by the Romanian government in July 2003 forecasts the rehabilitation of 4 units.

5.1 Description of the Production Facilities

5.1.1 Turceni TPP

The Turceni TPP consists of seven electricity generating units. Set out below is a brief description of the generating units' technical endowments, rehabilitation history and programme (with resultant investment requirements) and historical power production.

5.1.1.1 Technical Endowment

Each of the seven electricity generating units has an installed capacity of 330 MW. Units 1 through 4 were commissioned during the period 1978 – 1982, whereas units 5 to 7 were commissioned during the period 1983 – 1987. According to the Management, in conformity with the technical norms, the useful life of the Turceni TPP electricity generation units is approximately 25 years (assuming 8760 hours of operation per year), with major rehabilitation works being capable of prolonging such useful life to 40 years.

All units were submitted to various refurbishment works.

- *CURRENT STATUS*

The current technical state, as well as the schedule of production over the next 15 years have been estimated by Management as follows:

Unit no. 1 – will be kept in operation until 2008, thereafter it will be scrapped;

Unit no. 2 – has been shut down since 2000 and will be scrapped;

Unit no. 3 – was rehabilitated during the A2 Program and is currently operating. It is planned to be closed for rehabilitation works in 2008 – 2009, after which it will function until 2024;

Unit no. 4 – was rehabilitated during the A3 Program and resumed operation in 2002. It is expected to be in function until 2017;

Unit no. 5 – currently under rehabilitation within A3 Program and planned to be commissioned in December 2005. After that date, Unit 5 is estimated to be in operation up to 2020;

Unit no. 6 – was subject to minor repair and maintenance works in the A1 Program and is currently operational. However, it is planned to be closed for more important rehabilitation works during 2006 – 2007, after which it is estimated to be in operation to 2022;

Unit no. 7 – is planned to be functional until 2009, after which it will be scrapped.

5.1.1.2 Necessary Investments

The investment plan for the coming years, prepared by the plant management, includes the following salient features:

- rehabilitation of Unit 5 – same basic engineering as for unit 4 – commissioning expected during December 2005;
- installation of FGD units for units 3,4,5,6;
- rehabilitation of units 3 and 6;
- improvement of control capabilities as per UCTE requirements for two units;
- modernization of the cooling towers;
- increase of ash storage capacity;
- covering one coal unloading facility for protection during winter and bad weather.

For the forecast period the value of the necessary investment, according to TEC management is USD 1,100 million.

5.1.1.3 Historical Output

The output of the seven units over the past 10 years has been as follows:

Table 1. Turceni TPP Annual Energy Output, between 1994 - 2003 (GWh)

Year	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	Unit 7	Total output of TPP
1994	1,014	1,144	820	-	-	1,347	139	**4,464**
1995	877	1,421	343	-	-	1273	714	**4,628**
1996	697	1,047	109	-	-	1,129	1,651	**4,633**
1997	357	650	1,207	-	-	340	953	**3,507**
1998	136	17	1,118	-	-	788	957	**3,016**
1999	540	-	1,100	-	-	637	1,171	**3,448**
2000	1,194	-	1,672	-	-	400	1,782	**5,048**
2001	1,296	-	1,453	-	-	1,269	1,160	**5,178**
2002	916	-	969	1194	-	1,132	1,583	**5,794**
2003	1,400	-	1,168	2032	-	1,016	1,170	**6,786**

Source: the Information Memorandum

5.1.2 Mining – Open Pits

5.1.2.1 Technical Endowment

Jilt Sud open pit was opened in 1974, as part of CNLO, and endowed with 8 rotor excavators, which are still in service. The first rotor excavator was put into service in 1978.

Jilt Nord open pit was opened in 1984, as part of the CNLO, and endowed with 9 rotor excavators.

Over the medium term, TEC intends to purchase another 2 more modern excavators to replace 3 existing excavators. It also intends to increase the operational efficiency of the conveyor belt system by making investments that will lead to an increase in the speed and width of the belts used.

5.1.2.2 Reserves and Output

According to the geological investigations performed, remaining coal industrial reserves as of end-2004 in the Jilt Nord open pit are estimated at 127 million tonnes, whereas for Jilt Sud such resources are estimated at 171 million tonnes. Based on the production estimates for the year 2004 (i.e. 1.9 million tones for Jilt Nord and 2.9 million tones for Jilt Sud), these resources would allow approximately 64 years of remaining production in the Jilt Nord open pit and of about 60 years in the Jilt Sud open pit.

The historical annual output of the two open pits is set out in the table below:

Table 2. Output at Jilt Sud and Jilt Nord Open Pits between 1999 – 2003 (thousand tones)

	1999	2000	2001	2002	2003
Jilt Sud	2,000	2,200	2,271	2,240	2,450
Jilt Nord	1,000	1,250	1,799	1,585	2,205
Total	**3,000**	**3,450**	**4,070**	**3,825**	**4,655**

Source: the Information Memorandum

The lignite extracted in the Jilt Nord and Sud open pits is of rather low quality, approximately 1600 – 1800 kcal/kg. Turceni TPP was built to operate with coal of such qualitative parameters.

Table 3. Average power heat of the output obtained during the last 5 years in (Kcal/kg)

	1999	2000	2001	2002	2003
Jilt Sud	1,647	1,643	1,729	1,724	1,766
Jilt Nord	1,543	1,620	1,676	1,676	1,732

Source: the Information Memorandum

5.1.2.3 Necessary Investments

The investment plan for the period 2004 – 2014, according to the Information Memorandum, entails the items below:

- the purchase of 91.55 hectares of land, of which 64.35 hectares represent agricultural plots of land and 27.2 hectares are forest;
- the continued reconstruction of the private farms in Bohorelu village, of the school and cemetery;

- the transformation of 90 hectares in the Bohorelu dump in ecological surface;
- the disassembling, the transport and the reassembling of the excavator to be purchased from Bustuchin (or from Sf. Gheorghe open pit);
- the assembly of certain deposit equipment (IH 35);
- the assembly of certain new belt carriers;
- the assembly of a new excavator type 1400.

The investment outlays estimated by Management for the 10-year period following 2005 amount to approximately USD 100 million.

5.2 Environmental protection

5.2.1 Major Environmental Issues and Costs for Turceni TPP

The major environmental issues for Tuceni Energy Complex are caused by SO_2, NO_x and dust emissions that primarily and directly pollute the air as well as the soil and water, with consequences on ecosystems and human health.

By passing GD no. 541/2003 establishing certain measures to limit emissions into the air of certain pollutants released by large combustion plants (with an installed capacity greater than 50 MW), Romania has adopted the provisions of EC Directive 2001/80 regarding the establishment of measures for limiting the emissions of the abovementioned plants.

In accordance with GD no. 541/2003, compliance with limits imposed by EC Directive 2001/80 should be accomplished by Turceni TPP no later than 1 January 2012.

The following table outlines the situation of noxious gas emissions of the Turceni TPP units in operation, as of 2003

Table 4. Situation of noxious gas emissions of power generating units in operation as of 2003.

No.	Unit	Noxious gas emissions (mg/Nm^3)	Limits imposed by EC Directive 2001/80/ (mg/Nm^3)
1.	Unit no.1	SO_2: 3658 - 4694 NO_x: 373 - 470 Dust: 97 – 135	SO_2: 400 NO_x: 500 Dust: 50
2.	Unit no.3	SO_2: 3672 - 4764 NO_x: 405 - 453 Dust: 94 – 112	SO_2: 400 NO_x:500 Dust: 50
3.	Unit no.4	SO_2: 3230 - 4353 NO_x: 399 - 540 Dust: 60 – 90	SO_2: 400 NO_x: 500 Dust: 50
4.	Unit no.6	SO_2: 3884 - 4401 NO_x: 355 - 496 Dust: 102 – 141	SO_2: 400 NO_x: 500 Dust: 50
5.	Unit no.7	SO_2: 3632 - 4595 NO_x: 320 - 474 Dust: 98 – 140	SO_2: 400 NO_x: 500 Dust: 50

Source: Information Memorandum

In accordance with Art. 6 of the GD 541/2003, Turceni TPP has prepared a program of progressive reduction of the annual emissions of SO_2, NO_x and dust.

FLUE GAS DESULPHURIZATION (FGD)

The total amount earmarked for installing FGDs on the Units TEC intends to maintain in operation over the next 10 years was estimated by TEC management to be approximately EUR 250 million.

DUST REDUCTION

In order to realize the desired dust reduction Turceni TPP has to modernize its electrostatic precipitators. The timetable for this modernization program is as follows:

- Modernization of the electrostatic precipitators to Unit no. 3 - 2008
- Modernization of the electrostatic precipitators to Unit no. 4 - 2009
- Modernization of the electrostatic precipitators to Unit no. 5 - 2004
- Modernization of the electrostatic precipitators to Unit no. 6 - 2006

SLAG AND FLY ASH DUMPS NECESSARY MEASURES

- Slag and fly ash discharge works to the dump no.1 (Valea Ceplea)- 2003 - 2012
- Slag and fly ash discharge works to the dump no.2 - 2003 - 2007
- Remediation of slag and ash dump no.2, compartments 1,2 and 3.

THERMAL POLLUTION OF THE JIU RIVER WATERS

Taking into account the fact that during summer time the temperature of discharge waters exceeds the limit imposed by the water management permit, i.e. 35°C, Turceni TPP has to improve its cooling systems by executing repair works to the cooling towers.

Protective measures referring to thermal pollution of the Jiu river waters

The temperature of discharge waters has to be below the limits imposed by the water management permit, i.e. 35°C, so Turceni TPP has to improve its cooling systems by executing heavy repair works to the cooling towers.

The measures regarding heavy repair works to the cooling towers are as follows:

- Restoration of cooling installations – tower no. 6 - 2005
- Restoration of cooling installations – tower no. 5 - 2006
- Restoration of cooling installations – tower no. 1 - 2007

REDUCTION OF NOISE LEVELS

In order to assess the occupational health hazard to onsite employees, a regular noise level measurement program has to be implemented for Turceni TPP, focusing on the turbines and adjacent areas. Based on the results of the measurements, personal protective equipment for employees working in areas with noise levels above the admissible limit may need to be provided.

5.2.2 Major Environmental Issues and Costs for the Jilt Open Pits

The Management considers as main environmental protective measures for Jilt quarries the following:

- Air
  - reducing particulate emissions at Jilt North and Jilt South loading points;
  - reducing particulate emissions at Jilt North and Jilt South belt conveyers;
  - setting up a vegetal protection screen against surface emission sources;
  - covering transportation belts with protection tops.
- Water
  - Improvement of water treatment process in settling ponds;
  - Improvement of domestic water treatment process;
  - Periodic cleaning of collection channels and settling ponds:
  - Monitoring program of wastewater discharges.
- Soil
  - Remediation of affected land;
  - Works to control and prevent soil erosion;
  - Rehabilitation of terrains.
- Noise
  - Reduce the noise level at the Belt conveyers system in Matasari and Bradet villages.

6. Valuation - Discounted Cash Flow (DCF) Method

6.1 DCF Method - Valuation Assumptions and Results

Applying the DCF Valuation Methodology described in Appendix 2 "Valuation Theory" we have estimated the discount rate at 13%.

As discussed above, 5 potential scenarios have been simulated, in an attempt to illustrate sensitivity to the following three variables: number of units modernized, number of FGDs installed and the extent to which the necessary investments for the mining operations are carried out.

The following three sections presents the methodology used in deriving the discount rate, the common set of hypotheses for all five scenarios, as supplied by the Management, the main differentiating assumptions underlying each scenario, as well as the valuation results derived under each scenario.

6.1.1 Discount rate

The discount rate was estimated at 13% based on the following information:

Nominal risk-free rate	5.1%
Expected LT inflation	3.2%
Real risk-free rate	1.9%
Equity risk premium	5.5%
Beta factor (re-geared)	0.81
Preliminary cost of equity	**6.4%**
Size premium	2.25%
Country risk-Romania	4.88%
Company specific risk[1]	1.00%
Selected real cost of equity	**14.50%**
Cost of debt – real	10.00%
Tax rate	16.00%
After tax real cost of debt	**8.40%**
Debt / invested capital (ideal ratio)	**30.00%**
Weighted Average Cost of Capital real	**13.0%**

6.1.2 Common Set of Assumptions for All Five Scenarios:

[1] The company-specific risk stems from factors as: the frequent changes in Company management which lead to a certain level of instability in the decisions related to TEC is current and future operations and the poor efficiency in the utilization of assets which reflects unfavourably upon the overall efficiency indicators of the Company.

a) Forecast Period:

The detailed cash flow forecasts were constructed for the 10-year period starting January 1, 2005 to December 31, 2014. The forecasts for the period January 1, 2015 to December 31, 2022 are a replication of the last detailde forecast (i.e. 2014)

b) Depreciation:

The Company uses a straight-line method for the depreciation of buildings and equipment based on the statutory useful lives set for taxation purposes.

Existing assets have been depreciated according to the Romanian regulations for straight-line depreciation and amortization and useful life.

New investments were depreciated using the straight-line method and an economic useful life limited to the maximum period of 15 years by which the life of the electricity generating units can be extended by such investments.

c) Provision for Taxation:

The current tax charge is provided at a rate of 16% throughout the projection period.

6.1.3 Differentiating Assumptions and DCF Valuation Results for Each of the Five Scenarios

6.1.3.1 Scenario no. 1 – "full investment"

The differentiating underlying assumptions of the "full investment" scenario can be summarized as follows:

- **Units modernized:** Units no. 3, 4, 5 and 6;
- **FGDs installed:** Units no. 3,4,5 and 6;
- **Investment plan for coalmines carried out:** Yes.

Based on the abovementioned assumptions, combined with the common set of assumptions for all scenarios (described in Chapter 6.1.2), and the computations presented in Appendix 1, the total share value of the Complex has been estimated as follows:

Table 5. Scenario no. 1 – Valuation Results

		Power Price (US$/MWh)		
		43	**45**	**47**
	11%	(22,043,907)	67,650,203	151,467,223
Discount	**13%**	(57,711,537)	**20,909,894**	94,863,441
Rate	**15%**	(82,721,960)	(13,010,307)	52,961,777

6.1.3.2 Scenario no. 2 – "medium investment w/ coalmines"

The differentiating underlying assumptions of the "medium investment w/ coalmines" scenario are as follows:

- **Units modernized:** Units no. 4 and 5;
- **FGDs installed:** Units no. 4 and 5;
- **Investment plan for coalmines carried out:** Yes.

Based on the abovementioned assumptions, combined with the common set of assumptions for all scenarios (described in Chapter 6.1.2), and the computations presented in Appendix 1, the total share value of the Complex has been estimated as follows:

Table 6. Scenario no. 2 – Valuation Results

		Power Price (US$/MWh)		
		43	**45**	**47**
	11%	(57,560,224)	4,791,761	67,143,744
Discount	**13%**	(53,492,089)	**2,460,804**	58,413,694
Rate	**15%**	(49,902,793)	811,417	51,525,624

6.1.3.3 Scenario no. 3 - "medium investment w/o coalmines"

The differentiating underlying assumptions of the "medium investment w/o coalmines" are:

- **Units modernized:** Units no. 4 and 5;
- **FGDs installed:** Units no. 4 and 5;
- **Investment plan for coalmines carried out:** No.

Based on the abovementioned assumptions, combined with the common set of assumptions for all scenarios (described in Chapter 6.1.2), and the computations presented in Appendix 1, the total share value of the Complex has been estimated as follows:

Table 7. Scenario no. 3 – Valuation Results

		Power Price (US$/MWh)		
		43	**45**	**47**
	11%	(60,332,465)	2,639,624	65,611,711
Discount	**13%**	(55,536,891)	**1,016,718**	57,570,325
Rate	**15%**	(51,332,696)	(36,183)	51,260,328

6.1.3.4 Scenario no. 4 – "reduced investment"

The differentiating assumptions underlying the "reduced investment" scenario are the following:

- **Units modernized:** Units no. 4 and 5
- **FGDs installed:** Units no. 3, 5 and 6;
- **Investment plan for coalmines carried out:** No**.**

Based on the abovementioned assumptions, combined with the common set of assumptions for all scenarios (described in Chapter 6.1.2), and the computations presented in Appendices 2 and 3, the total share value of the Complex has been estimated as follows:

Table 8. Scenario no. 4 – Valuation Results

		Power Price (US$/MWh)		
		43	**45**	**47**
	11%	109,980,132	181,521,913	250,092,281
Discount	**13%**	78,771,364	**142,205,632**	203,291,585
Rate	**15%**	55,165,053	112,038,130	167,039,421

6.1.3.5 Scenario no. 5 – "No investment"

The differentiating assumptions underlying the "No investment" scenario are the following:

- **Units modernized:** Unit no. 4;
- **FGDs installed:** None;
- **Investment plan for coalmines carried out:** No.

Based on the abovementioned assumptions, combined with the common set of assumptions for all scenarios (described in Chapter 6.1.2), and the computations presented in Appendix 1, the total share value of the Complex has been estimated as follows:

Table 9. Scenario no. 5 – Valuation Results

		Power Price (US$/MWh)		
		43	**45**	**47**
	11%	192,206,696	230,758,702	269,310,709
Discount	**13%**	181,149,738	**217,820,757**	254,491,776
Rate	**15%**	171,009,696	205,947,387	240,885,077

6.1.4 Sensitivity Analysis of the Value Function to Output

Scenario 1 – <u>output forecast as provided by the Management</u>

Year-->	US$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Forecast Period-->		1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	-	-	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,933	1,902	1,902	1,902	1,902
Electricity delivered by Unit #5	GWh	-	1,994	1,994	1,994	1,994	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #6	GWh	1,235	-	-	1,994	1,994	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	8,203	8,203	7,501	7,501	7,819	7,691	7,691	7,691	7,691
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	9.78%	9.78%	9.78%	9.78%
	GWh	555	597	597	546	546	706	834	834	834	834
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	-	-	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Electricity produced by Unit #5	GWh	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #6	GWh	1,325	-	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	8,800	8,800	8,047	8,047	8,525	8,525	8,525	8,525	8,525

DCF Preliminary Valuation Results – Scenario 1 – <u>output forecast as provided by the Management</u>

		Power Price (US$ / MWh)		
US$		43	45	47
	11%	(22,043,907)	67,650,203	151,467,223
Discount	13%	(57,711,537)	20,909,894	94,863,441
Rate	15%	(82,721,960)	(13,010,307)	52,961,777

Scenario no. 1 – <u>output forecast adjusted according to 2004 actual output level</u>

Year-->	US$	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Forecast Period-->		1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	824	478	478	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,352	838	838	-	-	1,137	1,426	1,426	1,426	1,426
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,535	1,398	1,398	1,398	1,398
Electricity delivered by Unit #5	GWh	-	1,994	1,994	1,965	1,965	1,535	1,398	1,398	1,398	1,398
Electricity delivered by Unit #6	GWh	789	-	-	1,763	1,763	1,507	1,426	1,426	1,426	1,426
Electricity delivered by Unit #7	GWh	811	406	406	-	-	-	-	-	-	-
TOTAL ENERGY	GWh	5,677	5,681	5,681	5,693	5,693	5,715	5,650	5,650	5,650	5,650
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	9.78%	9.78%	9.78%	9.78%
	GWh	413	413	413	414	414	516	612	612	612	612
Electricity to be produced											
Electricity produced by Unit #1	GWh	884	513	513	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,450	899	899	-	-	1,240	1,581	1,581	1,581	1,581
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	1,674	1,550	1,550	1,550	1,550
Electricity produced by Unit #5	GWh	-	2,139	2,139	2,108	2,108	1,674	1,550	1,550	1,550	1,550
Electricity produced by Unit #6	GWh	846	-	-	1,891	1,891	1,643	1,581	1,581	1,581	1,581
Electricity produced by Unit #7	GWh	870	435	435	-	-	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	6,090	6,094	6,094	6,107	6,107	6,231	6,262	6,262	6,262	6,262

DCF Preliminary Valuation Results – Scenario 1 –<u>output forecast adjusted according to 2002 - 2004 actual output level</u>

US$		Power Price (US$ / MWh)		
		43	**45**	**47**
Discount Rate	**11%**	(225,287,804)	(136,292,564)	(47,688,449)
	13%	(248,158,616)	(170,221,298)	(92,633,019)
	15%	(261,627,571)	(192,594,576)	(123,873,685)

7. Valuation – Adjusted Net Assets Approach

The Adjusted Net Assets valuation approach is a balance-sheet-oriented valuation method. Essentially, this entails that the Company's balance sheet is restated to reflect the basic market value of the assets and liabilities. This typically involves the identification and valuation of otherwise unrecorded tangible and intangible assets, as well as the revaluation of the asset and liability accounts already recorded on the balance sheet.

The Adjusted Net Assets approach is not a primary indicator of value, but as TEC is a capital-intensive business, the value derived using the Adjusted Net Assets Approach could be useful in providing an indication of the fair value of the Company. Adjustments to the Financial Statements issued at December 31st, 2004 are proposed in accordance with the International Financial Reporting Standards. The analysis underlying the proposed adjustments is based on the findings of our financial analysis of the Energy Complex performed during June 2005.

7.1 Financial analysis and proposed corrections

The following are the adjustments proposed on the balance sheet items:

7.1.1 Land and Buildings

We have increased the value of Land by USD 26.2 million by incorporating the land for which the company has obtained ownership titles during 2004 and for which the administrative procedure for incorporating in the patrimony was not yet completed.

We have provided for the buildings pertaining to the Units 2 and 8 (which were closed and not functioning, respectively) in value of USD 0.1 million.

7.1.2 Inventory

Major inventory items of the Company are coal and spare parts for the boilers and turbine. Part of the spare parts inventory has very slow or no movement. Management has indicated that these are specialized spare parts and can only be purchased on large quantities or have a high value and they are necessary for emergency as well as planned intervention to the equipment. We estimate that inventory is valued at the proper value.

7.1.3 Receivables

The company's main debtors are state-owned companies purchasing power form it. Termoelectrica (the former shareholder of TEC) owes large amounts to the Company following the patrimony separation of the Complex from the holding company.

Termoelectrica is indebted to the Company in relation to energy deliveries during the period prior to the formation of the Energy Complex. Termoelectrica has not made any payments since the formation of the Complex, therefore we have proposed a provision of USD 7.8 million representing approximately 75% of the net amount due by Termoelectrica.

7.1.4 Payables

The Company has payables mainly to the fuel (heavy oil, natural gas etc.) purchases, fixed assets purchases and works (mainly repairs and maintenance) suppliers.

The Company has recorded in its books a debt of USD 23.9 million representing payables of Jilt and Dragotesti coal mines to Compania Nationala a Lignitului Oltenia (previously part of the same entity) taken over by TEC at its set up. According to Management the debt will be converted into shares which will be transferred to The Ministry of Economy and Commerce. We have adjusted the share capital with the value of this debt.

We estimate that payables are recorded at fair value in the Company's books.

7.1.5 Share capital

The Company's share capital is understated, in our opinion, by the amount corresponding to land for which the Company has received title deed and for which the Company has started the administrative procedures of incorporation into share capital. We have therefore adjusted the share capital value by the amount corresponding to such plots of land.

Table 10. Computation of the Adjusted Net Assets

	31-Dec-04	Adjustments	31-Dec-04 Adjusted
ASSETS			
Fixed Assets			
Tangible fixed assets	425.3	(0.1)	425.2
Land	21.9	26.2	48.1
Intangible fixed assets	0.2		0.2
TOTAL Fixed Assets	**447.4**		**473.5**
Current assets			-
Inventory	31.1		31.1
Receivables	146.6	(7.8)	138.8
Cash and cash equivalents	12.3		12.3
Prepayments	0.1		0.1
TOTAL Current assets	**190.1**		**182.3**
TOTAL ASSETS	**637.6**		**655.9**
			-
EQUITY AND LIABILITIES			-
Equity			-
Share capital	156.7	54.5	211.2
Revaluation reserves	193.7	-	193.7
Other Reserves	71.5	-	71.5
Retained Earnings	16.1	(4.4)	11.6
TOTAL Equity	**437.9**	-	**487.9**
Environmental provision	**3.3**		**3.3**
Non current liabilities			**-**
Deferred tax	0.0		0.0
Trade and other payables	93.2		93.2
Long term portion borrowings of interest bearing borrowings			-
Total non current liabilities	**93.3**		**93.3**
Current Liabilities			-
Trade and other payables	103.1	(31.7)	71.3
Short term portion of interest bearing borrowings			-
TOTAL Current Liabilities	**103.1**		**71.3**
TOTAL EQUITY AND LIABILITIES	**637.6**		**655.9**

As can be seen in Table 10 above, the equity value derived via the private company transaction method is USD 488 million (rounded) and represents a control value.

This result should be cautiously read since significant investments are needed in order to comply with EU environment directives beyond 2010. **If those investments would be taken into consideration with a present value ranging between 200 and 430 million USD then, the 100% equity value of TPP may result in a significantly reduced amount.**

In our opinon the higher value of the equity resulting from the application of the NAV method (especially compared with the results of the Market based approach) is an indication of a relative inefficient use of the assets.

8. Valuation – Market Approach

The Market approach is based on market data and is designed to determine the value of the business entity by comparing the subject company to (1) comparable entities (guideline companies) whose shares are publicly traded on organized capital markets (Guideline Company method) and/or (2) guideline companies that have been bought or sold during a reasonably recent period of time (Transactions method).

In either case, an appropriate sample of guideline companies is selected based on comparability criteria. Ideal guideline companies are those which are in the same industry as the subject company with comparable operations in terms of products, diversification, economic influences, and size among other factors.

8.1 Market-based Approach –Methodology Applied

8.1.1 Guideline Public Company Method

One method for valuing a Company is to apply multiples to earnings after tax, EBIT or EBITDA. In order to select the appropriate multiples, publicly-traded investment opportunities that are comparable to the subject company are analyzed, and are compared to the subject business taking into account, amongst others, relative investment risk, expected growth, etc.

However, in the case of TEC, the guideline public company method did not yield meaningful valuation results, as a meaningful sample of similar and relevant guideline public companies could not be obtained. Further, the guideline public company method is most useful when valuing minority interests. This is not the case for TEC where the purpose of this valuation is for a 100% controlling interest.

8.1.2 Transaction Method

The comparable transaction method is very similar to the public guideline company method. In this method, the subject company is compared to similar companies, which have recently been traded.

The following sources of information on relevant transactions of public and private companies were considered within the above-stated SIC classifications:

- Mergerstat Deal Report, within the ”Electricity Producers” Classification.
- Annual Reports of some of the largest European companies involved in the Electric Services industry.
- The Official Energy Statistics from the US Government page[2]
- The US Department of Energy – Office of Fossil Energy [3] which provided energy overviews of countries in Central and Eastern Europe.

[2] Source: http://www.eia.doe.gov/

[3] Source: http://www.fe.doe.gov/

The sources, which consist of transactions in relation to similar assets in Central and Eastern Europe, located transactions within TEC's general industry group. As mentioned before, with any analysis of this type and scale, information availability is often sketchy and incomplete. Moreover, information related to these transactions can be misleading because economies of scale and synergies, which are considered in a buyer's analysis, are difficult or impossible to calculate based on historical public information. Also (as described more at length in Appendix 5 "Overview of the Privatization Process in Selected Countries of Central and Eastern Europe"), when privatized, the state-owned company is sold to private investors in several steps, until the investor reaches control of the entity. The investor is then obliged by the terms of the contract to invest significantly in the power plant on several trances over several years, in order to attain measurable milestones. The actual multiple derived from the sale of such an entity, is therefore distorted. We conducted our analysis keeping these limitations in mind.

Moreover, the results of this method of valuation should be viewed in conjunction with the conclusions of the overview of the energy markets of the countries where such companies are active (i.e. the Czech Republic, Poland and Bulgaria) described in Appendix 5. The differences between the electricity market models of these countries and the electricity market rules adopted by Romania pose an additional limitation on the comparability of the five transactions listed below and the future privatization of TEC. The major difference (present mostly for transactions that occurred in Poland and Bulgaria) reside in the granting of government-backed PPAs to the privatized generators, which offered the perspectives of a secure and constant stream of revenues for long periods. Such significant incentives, which can distort the selling price of an electricity generating company and make the transaction much more appealing for an investor, are not allowed under the electricity market model adopted by Romania.

In addition to PPAs, similar transactions from comparable CEE countries may also be a biased reference due to: longer transition periods negotiated by the respective countries for meeting EU environmental norms, better shape and more efficient use of the technologies etc.

As can be seen in Table 11, data on five transactions of companies with sales from approximately $80 million to $300 million were found. The valuation ratios of MVIC/Revenues for the transactions ranged between a low of 0.72 and a high of 1.16.

The business descriptions of some of the acquirers and target companies in the five transactions are summarized below:

- ***Sokolovska uhelna a.s.***[4] ("Sokolovska"), the seller, is the largest independent electricity producer in Czech Republic with 620 MW generating capacity. Its main business activities are the extraction of brown coal and the processing of the latter into value-added forms of energy. Sokolovska is a dynamic fuel-energy complex with annual production of around 10 million tons of brown coal, 6 million tons of which is sold in domestic and export markets. The company's aggregate power generation capacity is 620 MW. In 2003, the overall production of electric power totalled 3,430 GWh.

  Method of sale: at the beginning of August 2003 marked the privatization process of the state-owned brown coal companies Severoceske doly (with 55.4 state ownership participation) and Sokolovska (with a 50.2% state-owned capital).More than ten companies expressed interest, but most of them did not make it through the pre-qualification round. On March 2004 the Government of the Czech Republic approved the sale of shares of

[4] Source: 2003 Annual Report Sokolovska uhelna a.s.

Sokolovska as held by the National Property Fund of the Czech Republic, to the company Sokolovska tezebany a.s.

- ***Electrownia Rybnik***[5] ("Rybnik"), the seller, is one of the biggest power stations in Poland, with 1,775 MW generating capacity installed in eight units, and producing approximately 9,000 GWh of electric energy.The cooling system of the plant uses artificial water. Boilers installed in Rybnik are fed hard coal supplied by few neighbouring coal mines. Annual consumption of coal for energy generation amounts to approximately 4 million tons.

  Method of sale: the privatization of Rybnik was performed on several trances. In the first trance performed on March 28, 2001, Electricite de France and Energie Baden-Wuerttemberg ("EDF-EnBW" consortium) acquired from the Polish Government a 35% strategic minority stake in Rybnik for $120 million. The agreement was made with the view of future acquisitions to reach a majority stake. In the second trance, on October 22, 2001 EDF-EnBW increased their combined holding in Rybnik from 35% to 50% for 56.6 million Euro. In the third trance, an additional 35% was acquired for $117 million, and as a result, the combined EDF-EnBW held at that time an 85% stake in the company.

- ***Maritza East III***[6] ("Maritza"), the seller, is one of the three power plants of the Maritza East power complex. It is located in the southern part of Bulgaria, near the town of Stara Zagora. Maritza is a base-load condense-type power plant. It consists of a total generating capacity of 840 MW (consisting of four 210 MW units commissioned over the period 1978 - 1981). The plant burns lignite from the Maritza East coal field. In 2003, the power plant produced 4,293 GWh of electricity.

  Method of sale[7]: on March 5, 2003, Enel Produzione acquired for Euro 75.7 million a 60% share in the capital stock of Dutch company Entergy Power Holding Maritza BV, which in turn controlled 73% of Maritza East III Power Company AD. The latter will carry out the refurbishment and environmental upgrade of the lignite-fired generation plant, subsequently managing the plant. Enel holds a call option on 40% of the capital stock of Entergy Power Holding Maritza BV. Also with reference to the acquisition of Maritza, the amount of euro 76 million paid for a 60% share in the holding company that controls Maritza is offset by the amount of cash held at the time of the purchase by the operating entity (euro 75 million) to be employed in the revamping of the power plant owned by the same.

- ***Elektrocieplownie Warszawskie S.A.***[8] ("EC Warszawskie"), the seller, comprises five power plants located in the Warsaw area. Hard coal is the main fuel fired by EC Warszawskie and its annual consumption is more than 3 million tons. Company's aggregate power generation capacity is 928 MW.

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[5] Source: http://www.elektrownia.rybnik.pl

[6] Source: Annual report 2003 of NEK EAD

[7] Source: 2003 Annual Report Enel

[8] Source: http://www.ewsa.com.pl

Method of sale: on January 2000, Vattenfall AB acquired a 55% stake in EC Warszawskie for $235 million. At that time, Vattenfall planned to invest a further $600 million in EC Warszawskie over the next 10 years.

- ***Elektrocieplownia Krakow S.A.***[9] ("EC Krakow"), the seller, is a condensing and thermal generating power station. EC Kraków generates electricity and heat in 4 power units and in 5 peak heat-only boilers. Heat is supplied to the municipal district heating system in the form of heated water (for residential heating) and process steam (for industrial facilities and hospitals). The utility Company's aggregate power generation capacity is 460 MW.

  Method of sale: on June 1, 1998, Electricite de France acquired from the Polish government a 50% stake in the EC Krakow.

For each firm in the sample of guideline companies, several value indications or pricing multiples are calculated. Examples of pricing multiples include: price to earnings, price to cash flow and price to book value. After these multiples are calculated for each guideline company, an appropriate value multiple is selected for the subject company based on a thorough analysis of the subject company's risk and financial characteristics compared to the guideline companies. This multiple is then applied to the appropriate financial data (e.g., earnings, cash flow, book value) of the subject business.

In this case, two multiples were used to derive a value of TEC through the market-based approach: EBIT and revenue. The main reasons for employing both EBIT and revenue multiples was to determine the sensitivity of TEC value to operational efficiency. Since TEC is a capital-intensive business, the efficiency with which it employs the assets (which require high capital, repair and maintenance expenses) is decisive for its profitability. By analyzing the difference between revenue-based and EBIT-based multiples for TEC's comparables, the Company's operating performance compared to similar and relevant companies in its industry can be assessed.

[9] Source: http://www.eck-sa.krakow.pl

As it can be seen in Table 11 below, the median result of MVIC/Revenues multiple for the five transactions was 1.02.

Table 11. Transaction method – valuation results

No.	Source of Data (a)	Announced	Closed	Buyer	Seller	Target Business Description	Target Country	Percent Sought	Deal Size (Base Equity Price) (million)	Target Nominal MW	TargetEBIT LTM (million $ or Euro)	EBIT/ Revenues LTM(%)	Deal Size (equivalent of 100% purchase) (million)	Target Revenue LTM(million)	Deal Size/ Target Revenues	Deal Size/ Target EBIT
1	M/AR	21-Mar-04	21-Mar-04	Sokolovska tezebni a.s.	Sokolovska uhelna a.s	Coal mining with thermal power	Czech Republic	50.20 %	€ 79.0	620 MW	€ 13.5	6.1%	€ 157.4	€ 219.0	0.72	11.69
2	AR	2001-2003	25-Jun-03	Electricite de France / Energie Baden	Electrownia Rybnik	TP using coal	Poland	85.00 %	$304.9	1,775 MW	$28.5	9.1%	$358.7	$313.4	1.14	12.60
3	M/AR	5-Mar-03	1-May-03	Enel Produzione	Entergy Power Maritza BV	TP Plant using lignite	Bulgaria	43.80 %	€ 75.7	840 MW	n/a	n/a	€ 97.8	€ 107.5	0.91	
4	AR		1-Jan-00	EDF	EC Warszawskie	Thermal Power Plant using hard coal	Poland	55.00 %	$235.0	928 MW	$4.3	1.4%	$352.3	$302.6	1.16	
5	AR		1-Jun-98	EDF	EC Krakow	Electricity and heat generator	Poland	50.00 %	$79.8	460 MW	$8.4	10.1%	$84.6	$83.0	1.02	10.06

(a) M = Mergerstat International Database
AR = Buyer or Seller's Annual Reports

Median - All transactions		157.4	219.0	**1.02**	**11.69**
Range	**high**	358.7	313.4	1.16	12.60
	low	84.6	83.0	0.72	10.06

	Based on Revenues:	Based on EBIT:
2004 Revenues/ EBIT for Turceni Electric Complex ($) =	209,380,188	11,099,855
Multiple used =	**1.02**	**12.1**
100% Equity =	213,416,432	129,754,240
Minus Debt =		
100% Equity Rounded ($) =	**213,416,000**	**129,754,000**

Table 12. Transaction method – valuation results

Market Value Ratio	Ratio	Parameter (USD)	Indicated Value (USD, rounded)
Market Value of Invested capital/			
December 31, 2004 Revenues (extrapolated for 12 months)	1.02	209,380,188	213,416,000
December 31, 2004 EBIT (extrapolated for 12 months)	11.7	11,099,855	129,754,000

As can be seen in Table 12 above, the equity value derived via the private company transaction method ranges from USD 129 to 213 million (rounded) and represents a control value. This result should be cautiously read since significant investments are needed in order to comply with EU environment directives beyond 2010. **If those investments would be taken into consideration with a present value ranging between 200 and 430 million USD then, the 100% equity value of TPP may result in a negative amount.**

The significant difference between the two methods (making EBIT-based value 60% of the revenue-based value) reflects the poor efficiency in the utilization of TEC assets compared to the efficiency in the operation of the companies selected for comparison. EBIT reflects the earning power of a company from its ongoing operations, whereas revenues as a stand-alone indicator disregard the expenses incurred in their generation.

EBIT may be considered the more relevant indicator and, in the case of TEC, it shows that operating expenses (incurred in the usual course of business – i.e. power generation using the assets base) are too large, leaving too small a share of the revenues earned within the company. The cause may be the underutilization of assets in the production of electricity (i.e. the generation of revenues). Such assets, although not used or improperly utilized, still increase operating expenses by their depreciation.

9. Appendix 1 – DCF detailed computations

9.1 Scenario 1

Table 13. Scenario no. 1 – Investment Program

Year		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Forecast Period		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
CAPEX											
Total fixed assets acquisitions, at book value	**USD**	**91,293,895**	**53,366,381**	**147,968,188**	**185,982,628**	**319,645,527**	**204,868,236**	**77,265,107**	**65,439,543**	**15,518,347**	**14,556,000**
Rehabilitation of Unit 3 (Euro) putting in function December 2010	EUR	40,000	4,460,000	0	900,000	77,391,441	70,558,050				
Rehabilitation of Unit 6 (in Euro) putting in function June 2008	EUR	0	46,000	4,954,000	51,900,000	59,860,228	29,930,114	0	0	0	0
Flue Gas Desulphuration Unit 3-6 (in Euro) putting in function December 2010	EUR	637,923	621,354	44,812,018	59,641,656	87,486,580	41,895,799	15,177,595	0	0	0
Ceplea 195	EUR	27,649,825	3,200,788	4,628,832	4,711,904					0	0
Ceplea 215	EUR						4,864,136	17,028,410	6,967,960	5,942,578	5,226,406
Slam dens (scenariu pesimist) PIF 2007 dec	EUR				10,000,000	40,000,000	30,000,000	20,000,000	20,000,000	0	0
Investment necesarry to conclude the modernization of Unit 5 (in Euro)	EUR	50,330,975	11,300,878	0	0	0	0	0	0	0	0
Mining - investment 1 Environmental, land expropriation, other repairs (EUR)	EUR	6,015,935	5,860,922	5,812,542	5,443,795	1,812,515	1,812,525	1,812,525	1,987,742	2,378,742	1,745,947
Mining - investment 2 Capacity increase (EUR)	EUR	8,198,800	8,198,800	3,739,677	3,641,292	3,113,495	3,120,667	3,930,300	20,123,955	3,317,440	3,944,647
Other investment (Euro) Unit 4 Electrofilter	EUR	0	0	0	0	0	1,400,000	0	0	0	0
NOx reduction investment (Euro)	EUR	0	0	0	0	0	0	0	0	0	2,000,000

Table 14. Scenario no. 1 – Electricity Sold

	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast period	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	-	-	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,933	1,902	1,902	1,902	1,902
Electricity delivered by Unit #5	GWh	-	1,994	1,994	1,994	1,994	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #6	GWh	1,235	-	-	1,994	1,994	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	8,203	8,203	7,501	7,501	7,819	7,691	7,691	7,691	7,691
		-	-	-	-	-	-	-	-	-	-
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	9.78%	9.78%	9.78%	9.78%
	GWh	555	597	597	546	546	706	834	834	834	834
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	-	-	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Electricity produced by Unit #5	GWh	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #6	GWh	1,325	-	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	8,800	8,800	8,047	8,047	8,525	8,525	8,525	8,525	8,525

Table 15. Scenario no. 1 – Specific Fuel Consumption

		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Specific consumption (grams cc/KWh)												
for Unit #1	grams cc/KWh		375	378	379							
for Unit #2	grams cc/KWh											
for Unit #3	grams cc/KWh		373	375	376			358	358	358	358	358
for Unit #4	grams cc/KWh		358	358	358	359	360	361	362	363	364	365
for Unit #5	grams cc/KWh		365	358	358	358	358	358	359	360	361	362
for Unit #6	grams cc/KWh		377			358	358	358	358	358	359	360
for Unit #7	grams cc/KWh		372	374	375	376	377					

Table 16. Scenario no. 1 – Fuel Prices

Forecasted prices for fuels (VS)		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Cost of Heavy Oil	USD/ton		158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53
Cost related to transportation of Heavy Oil	USD/ton		7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Cost of Natural Gas	USD/'000m3		122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50
Cost of coal produced in TEC-own mines (w/o depreciation)	USD/ton		13.47	13.47	13.17	13.11	12.64	12.64	12.92	12.71	12.32	12.65
Cost of coal bought from third parties	USD/ton		15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34
Cost related to transportation of coal	USD/ton		3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Energy from medium voltage distribution	USD/MWh		66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67
Limestone	USD/ton		13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Transport of limestone	USD/ton		4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67

9.2 Scenario 2

Table 17. Scenario no. 2 – Electricity Sold

	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	-	-	-	-	-	-	-
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,933	1,902	1,902	1,902	1,902
Electricity delivered by Unit #5	GWh	-	1,495	1,994	1,994	1,994	1,962	1,930	1,930	1,930	1,930
Electricity delivered by Unit #6	GWh	1,235	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	7,705	8,203	5,507	5,507	3,895	3,832	3,832	3,832	3,832
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	9.78%	9.78%	9.78%	9.78%
	GWh	555	560	597	401	401	352	415	415	415	415
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	-	-	-	-	-	-	-
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Electricity produced by Unit #5	GWh	-	1,604	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #6	GWh	1,325	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	8,265	8,800	5,908	5,908	4,247	4,247	4,247	4,247	4,247

Table 18. Scenario no. 2 – Specific Fuel Consumption

		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Specific consumption (grams cc/KWh)												
for Unit #1	grams cc/KWh		375	378	379							
for Unit #2	grams cc/KWh											
for Unit #3	grams cc/KWh		373	375	376							
for Unit #4	grams cc/KWh		358	358	358	359	360	361	362	363	364	365
for Unit #5	grams cc/KWh		365	358	358	358	358	358	359	360	361	362
for Unit #6	grams cc/KWh		377									
for Unit #7	grams cc/KWh		372	374	375	376	377					

Table 19. Scenario no. 2 – Fuel Prices

Forecasted prices for fuels (VS)	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Cost of Heavy Oil	USD/ton	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53
Cost related to transportation of Heavy Oil	USD/ton	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Cost of Natural Gas	USD/'000m3	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50
Cost of coal produced in TEC-own mines (w/o depreciation)	USD/ton	13.47	13.47	13.17	13.11	12.64	12.64	12.92	12.71	12.32	12.65
Cost of coal bought from third parties	USD/ton	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34
Cost related to transportation of coal	USD/ton	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Energy from medium voltage distribution	USD/MWh	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67
Limestone	USD/ton	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Transport of limestone	USD/ton	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67

Table 20. Scenario no. 2 - Investment Program

		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Forecast Period-->		1	2	3	4	5	6	7	8	9	10
CAPEX											
Total fixed assets acquisitions, at book value	**USD**	**90,753,946**	**40,400,145**	**48,893,509**	**65,207,887**	**118,225,733**	**82,860,303**	**67,146,710**	**65,439,543**	**15,518,347**	**14,556,000**
Rehabilitation of Unit 3 (Euro) putting in function December 2010	EUR										
Rehabilitation of Unit 6 (in Euro) putting in function June 2008	EUR										
Flue Gas Desulphuration Unit 3-6 (in Euro) putting in function December 2010	EUR	318,962	318,962	310,677	22,406,009	29,820,828	43,743,290	20,947,900	7,588,798	0	0
Ceplea 195	EUR	3,200,788	4,628,832	4,711,904					0	0	0
Ceplea 215	EUR						4,864,136	17,028,410	6,967,960	5,942,578	5,226,406
Slam dens (scenariu pesimist) PIF 2007 dec	EUR				10,000,000	40,000,000	30,000,000	20,000,000	20,000,000	0	0
Investment necessary to conclude the modernization of Unit 5 (in Euro)	EUR	22,681,150	50,330,975	11,300,878	0	0	0	0	0	0	0
Mining - investment 1 Environmental, land expropriation, other repairs (EUR)	EUR	6,015,935	6,015,935	5,860,922	5,812,542	5,443,795	1,812,515	1,812,525	1,812,525	1,987,742	2,378,742
Mining - investment 2 Capacity increase (EUR)	EUR	8,198,800	8,198,800	3,739,677	3,641,292	3,113,495	3,120,667	3,930,300	20,123,955	3,317,440	3,944,647
Other investment (Euro) Unit 4 Electrofilter	EUR	0	0	0	0	0	1,400,000	0	0	0	0
NOx reduction investment (Euro)	EUR	0	0	0	0	0	0	0	0	0	2,000,000

9.3 Scenario 3

Table 21. Scenario no. 3 – Electricity Sold

	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	-	-	-	-	-	-	-
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,933	1,933	1,933	1,933	1,933
Electricity delivered by Unit #5	GWh	-	1,994	1,994	1,994	1,994	1,962	1,962	1,962	1,962	1,962
Electricity delivered by Unit #6	GWh	1,235	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	8,203	8,203	5,507	5,507	3,895	3,895	3,895	3,895	3,895
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	8.28%	8.28%	8.28%	8.28%
	GWh	555	597	597	401	401	352	352	352	352	352
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	-	-	-	-	-	-	-
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Electricity produced by Unit #5	GWh	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #6	GWh	1,325	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	8,800	8,800	5,908	5,908	4,247	4,247	4,247	4,247	4,247

Table 22. Scenario no. 3 – Specific Fuel Consumption

		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Specific consumption (grams cc/KWh)												
for Unit #1	grams cc/KWh		375	378	379							
for Unit #2	grams cc/KWh											
for Unit #3	grams cc/KWh		373	375	376							
for Unit #4	grams cc/KWh		358	358	358	359	360	361	362	363	364	365
for Unit #5	grams cc/KWh		365	358	358	358	358	358	359	360	361	362
for Unit #6	grams cc/KWh		377									
for Unit #7	grams cc/KWh		372	374	375	376	377					

Table 23. Scenario no. 3 – Fuel Prices

Forecasted prices for fuels (VS)	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Cost of Heavy Oil	USD/ton	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53
Cost related to transportation of Heavy Oil	USD/ton	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Cost of Natural Gas	USD/'000m3	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50
Cost of coal produced in TEC-own mines (w/o depreciation)	USD/ton	13.47	13.47	13.17	13.11	12.64	12.64	12.92	12.71	12.32	12.65
Cost of coal bought from third parties	USD/ton	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34
Cost related to transportation of coal	USD/ton	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Energy from medium voltage distribution	USD/MWh	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67
Limestone	USD/ton	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Transport of limestone	USD/ton	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67

Table 24. Scenario no. 3 - Investment Program

			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->		1	2	3	4	5	6	7	8	9	10
CAPEX												
	Total fixed assets acquisitions, at book value	**USD**	**82,732,699**	**32,585,583**	**41,143,453**	**57,949,493**	**115,809,047**	**80,443,603**	**64,730,010**	**62,789,220**	**12,346,691**	**12,228,071**
1	Rehabilitation of Unit 3 (Euro) putting in function December 2010	EUR										
2	Rehabilitation of Unit 6 (in Euro) putting in function June 2008	EUR										
3	Flue Gas Desulphuration Unit 3-6 (in Euro) putting in function December 2010	EUR	318,962	318,962	310,677	22,406,009	29,820,828	43,743,290	20,947,900	7,588,798	0	0
4	Ceplea 195	EUR	3,200,788	4,628,832	4,711,904					0	0	0
5	Ceplea 215	EUR						4,864,136	17,028,410	6,967,960	5,942,578	5,226,406
6	Slam dens (scenariu pesimist) PIF 2007 dec	EUR				10,000,000	40,000,000	30,000,000	20,000,000	20,000,000	0	0
7	Investment necessary to conclude the modernization of Unit 5 (in Euro)	EUR	22,681,150	50,330,975	11,300,878	0	0	0	0	0	0	0
8	Mining - investment 1 Environmental, land expropriation, other repairs (EUR)	EUR	6,015,935									
9	Mining - investment 2 Capacity increase (EUR)	EUR	8,198,800	8,198,800	3,739,677	3,641,292	3,113,495	3,120,667	3,930,300	20,123,955	3,317,440	3,944,647
10	Other investment (Euro) Unit 4 Electrofilter	EUR	0	0	0	0	0	1,400,000	0	0	0	0
11	NOx reduction investment (Euro)	EUR	0	0	0	0	0	0	0	0	0	2,000,000

9.4 Scenario 4

Table 25. Scenario no. 4 – Electricity Sold

	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	-	-	1,577	1,551	1,551	1,551	1,551
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,949	1,918	1,918	1,918	1,918
Electricity delivered by Unit #5	GWh	-	1,994	1,994	1,994	1,994	1,978	1,946	1,946	1,946	1,946
Electricity delivered by Unit #6	GWh	1,235	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	8,203	8,203	5,507	5,507	5,504	5,415	5,415	5,415	5,415
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	7.53%	9.03%	9.03%	9.03%	9.03%
	GWh	555	597	597	401	401	448	537	537	537	537
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	-	-	1,705	1,705	1,705	1,705	1,705
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108	2,108
Electricity produced by Unit #5	GWh	-	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139	2,139
Electricity produced by Unit #6	GWh	1,325	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	8,800	8,800	5,908	5,908	5,952	5,952	5,952	5,952	5,952

Table 26. Scenario no. 4 – Specific Fuel Consumption

		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Specific consumption (grams cc/KWh)												
for Unit #1	grams cc/KWh		375	378	379							
for Unit #2	grams cc/KWh											
for Unit #3	grams cc/KWh		373	375	376							
for Unit #4	grams cc/KWh		358	358	358	359	360	361	362	363	364	365
for Unit #5	grams cc/KWh		365	358	358	358	358	358	359	360	361	362
for Unit #6	grams cc/KWh		377									
for Unit #7	grams cc/KWh		372	374	375	376	377					

Table 27. Scenario no. 4 – Fuel Prices

Forecasted prices for fuels (VS)		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Cost of Heavy Oil	USD/ton		158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53
Cost related to transportation of Heavy Oil	USD/ton		7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Cost of Natural Gas	USD/'000m3		122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50
Cost of coal produced in TEC-own mines (w/o depreciation)	USD/ton		13.47	13.47	13.17	13.11	12.64	12.64	12.92	12.71	12.32	12.65
Cost of coal bought from third parties	USD/ton		15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34
Cost related to transportation of coal	USD/ton		3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Energy from medium voltage distribution	USD/MWh		66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67
Limestone	USD/ton		13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Transport of limestone	USD/ton		4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67

Table 28. Scenario no. 4 – Investment Program

			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->		1	2	3	4	5	6	7	8	9	10
CAPEX												
	Total fixed assets acquisitions, at book value	**USD**	**82,945,340**	**32,792,701**	**56,080,793**	**77,830,045**	**144,971,240**	**94,408,870**	**69,789,208**	**62,789,220**	**12,346,691**	**12,228,071**
	Assets entered into production -> ready for depreciation	**USD**	**18,952,980**	**10,931,733**	**176,020,338**	**4,986,236**	**21,577,088**	**4,151,327**	**6,027,556**	**88,664,708**	**193,680,557**	**164,423,253**
1	Rehabilitation of Unit 3 (Euro) putting in function December 2010	EUR										
2	Rehabilitation of Unit 6 (in Euro) putting in function June 2008	EUR										
3	Flue Gas Desulphuration Unit 3-6 (in Euro) putting in function December 2010	EUR	318,962	478,442	466,016	33,609,014	44,731,242	65,614,935	31,421,849	11,383,196	0	0
4	Ceplea 195	EUR	3,200,788	4,628,832	4,711,904					0	0	0
5	Ceplea 215	EUR						4,864,136	17,028,410	6,967,960	5,942,578	5,226,406
6	Slam dens (scenariu pesimist) PIF 2007 dec	EUR				10,000,000	40,000,000	30,000,000	20,000,000	20,000,000	0	0
7	Investment necessary to conclude the modernization of Unit 5 (in Euro)	EUR	22,681,150	50,330,975	11,300,878	0	0	0	0	0	0	0
8	Mining - investment 1 Environmental, land expropriation, other repairs (EUR)	EUR	6,015,935									
9	Mining - investment 2 Capacity increase (EUR)	EUR	8,198,800	8,198,800	3,739,677	3,641,292	3,113,495	3,120,667	3,930,300	20,123,955	3,317,440	3,944,647
10	Other investment (Euro) Unit 4 Electrofilter	EUR	0	0	0	0	0	1,400,000	0	0	0	0
11	NOx reduction investment (Euro)	EUR	0	0	0	0	0	0	0	0	0	2,000,000

9.5 Scenario 5

Table 29. Scenario no. 5 – Electricity Sold

	Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Electricity available for sale											
Electricity delivered by Unit #1	GWh	1,249	1,271	1,271	-	-	-	-	-	-	-
Electricity delivered by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #3	GWh	1,541	1,487	1,487	1,487	1,487	1,463	-	-	-	-
Electricity delivered by Unit #4	GWh	1,902	1,965	1,965	1,965	1,965	1,933	-	-	-	-
Electricity delivered by Unit #5	GWh	-	-	-	-	-	-	-	-	-	-
Electricity delivered by Unit #6	GWh	1,235	1,235	1,235	1,235	1,235	1,215	-	-	-	-
Electricity delivered by Unit #7	GWh	1,706	1,487	1,487	1,548	1,548	-	-	-	-	-
TOTAL ENERGY	GWh	7,632	7,445	7,445	6,235	6,235	4,612	-	-	-	-
Loss or own consumption		6.78%	6.78%	6.78%	6.78%	6.78%	8.28%	9.78%	9.78%	9.78%	9.78%
	GWh	555	541	541	454	454	416	-	-	-	-
Electricity to be produced											
Electricity produced by Unit #1	GWh	1,340	1,363	1,363	-	-	-	-	-	-	-
Electricity produced by Unit #2	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #3	GWh	1,653	1,595	1,595	1,595	1,595	1,595	-	-	-	-
Electricity produced by Unit #4	GWh	2,040	2,108	2,108	2,108	2,108	2,108	-	-	-	-
Electricity produced by Unit #5	GWh	-	-	-	-	-	-	-	-	-	-
Electricity produced by Unit #6	GWh	1,325	1,325	1,325	1,325	1,325	1,325	-	-	-	-
Electricity produced by Unit #7	GWh	1,830	1,595	1,595	1,661	1,661	-	-	-	-	-
TOTAL ENERGY PRODUCED	GWh	8,188	7,986	7,986	6,689	6,689	5,028	-	-	-	-

Table 30. Scenario no. 5 – Specific Fuel Consumption

		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Specific consumption (grams cc/KWh)												
for Unit #1	grams cc/KWh		375	378	379							
for Unit #2	grams cc/KWh											
for Unit #3	grams cc/KWh		373	375	376	376	376	376				
for Unit #4	grams cc/KWh		358	358	358	359	360	361				
for Unit #5	grams cc/KWh		365	358	358	358	358	358				
for Unit #6	grams cc/KWh		377	377	377	377	377	377				
for Unit #7	grams cc/KWh		372	374	375	376	377					

Table 31. Scenario no. 5 – Fuel Prices

Forecasted prices for fuels (VS)		Year-->	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
		Forecast Period-->	1	2	3	4	5	6	7	8	9	10
Cost of Heavy Oil	USD/ton		158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53	158.53
Cost related to transportation of Heavy Oil	USD/ton		7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90	7.90
Cost of Natural Gas	USD/'000m3		122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50	122.50
Cost of coal produced in TEC-own mines (w/o depreciation)	USD/ton		13.47	13.47	13.17	13.11	12.64	12.64	12.92	12.71	12.32	12.65
Cost of coal bought from third parties	USD/ton		15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34	15.34
Cost related to transportation of coal	USD/ton		3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
Energy from medium voltage distribution	USD/MWh		66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67	66.67
Limestone	USD/ton		13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Transport of limestone	USD/ton		4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67	4.67

Table 32. Scenario no. 5 – Investment Program

			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	Forecast Period-->		1	2	3	4	5	6	7	8	9	10
CAPEX												
	Total fixed assets acquisitions, at book value	**USD**	**8,021,247**	**7,814,563**	**7,750,056**	**7,258,393**	**2,416,687**	**4,283,367**	**0**	**0**	**0**	**0**
1	Rehabilitation of Unit 3 (Euro) putting in function December 2010	EUR										
2	Rehabilitation of Unit 6 (in Euro) putting in function June 2008	EUR										
3	Flue Gas Desulphuration Unit 3-6 (in Euro) putting in function December 2010	EUR	318,962									
4	Ceplea 195	EUR										
5	Ceplea 215	EUR										
6	Slam dens (scenariu pesimist) PIF 2007 dec	EUR										
7	Investment necessary to conclude the modernization of Unit 5 (in Euro)	EUR	22,681,150									
8	Mining - investment 1 Environmental, land expropriation, other repairs (EUR)	EUR	6,015,935	5,860,922	5,812,542	5,443,795	1,812,515	1,812,525				
9	Mining - investment 2 Capacity increase (EUR)							1,400,000				
10	Other investment (Euro) Unit 4 Electrofilter	EUR										
11	NOx reduction investment (Euro)	EUR										

10. Appendix 2 - Valuation Theory

10.1 Discounted Cash Flows Method

The Discounted Cash Flow methodology estimates the value of the equity of a business by estimating total business value and subtracting from it the market value of any debt used to fund operations via:

Total Share Value = Value of Business less Market Value of Debt Funding

Total Business Value comprises the following basic components:

- The present value of cash flows from operations during a forecasted period of operating the business plus the value of any marketable securities and other assets not essential to operations.
- An estimate of "residual value", which is the present value of the business attributable to operations beyond the forecast period.

Cash flow from operations is the difference between operating cash inflows and cash outflows adjusted for the cash taxes payable. Cash outflows should include any additional investments to both working capital and fixed assets that are necessary to support the Complex's business strategy as reflected in its cash inflows. The net after-tax cash flow represents cash available to pay back debt holders and pay dividends to shareholders (or reinvest in the business for future capital gains).

Residual value is computed as follows:

Future cash flows are considered as a perpetuity, a stream of cash flows proceeding on indefinitely. The value of such perpetuity (i.e., the value of the business at the end of the forecast period) is the value of the expected indefinite annual cash flow, divided by the weighted average cost of capital (WACC):

$$\text{Perpetuity Value} = \frac{\text{Annual Cash Flow Expected to Continue Indefinitely}}{\text{WACC} - \text{growth rate}}$$

This perpetuity value is then discounted to the present by the normal method to arrive at the residual.

In the DCF computations, the cash flow generated in the last year of the forecast period is expected to proceed indefinitely and thus is used to compute the residual value.

10.1.1 Discount Rate

The discount rate is the rate of return that investors would require for an investment in a specific business/project. It is applied to future cash flows of a business/project to take account of the expected risk premium of the investors on top of the normal return of risk-free investment.

By taking into consideration factors such as:

- Country risk premium;
- Market risk premium;
- Specific industry risk;
- Lack of historical financial performance of the Complex;
- Dependence on a limited number of clients;
- Lack of marketability of Complex's shares;
- Cost of Company's debt.

10.2 Net Asset Value Method

Net Asset Value is a balance-sheet-oriented valuation method, which makes sense for capital-intensive companies. Essentially, the company's balance sheet is restated to the defined value. This typically involves the identification and valuation of otherwise unrecorded tangible and intangible assets, as well as the revaluation of the asset and liability accounts already recorded on the balance sheet. This involves a separate identification and revaluation of the company's assets and liabilities, among which:

- Financial assets (e.g. cash, receivables, inventory etc.);
- Tangibles (e.g. machinery and equipment, furniture and fixtures, trucks and automobiles etc.);
- Intangibles (e.g. patents, trademarks and trade names, goodwill etc.);
- Current liabilities (e.g. accounts payable, taxes payable etc.);
- Long-term liabilities (e.g. loans, bonds etc.);
- Contingent liabilities (e.g. pending environmental matters, commercial litigation etc.);

Under this method, the value of the discretely appraised assets (both tangible and intangible) les the value of the discretely appraised liabilities (both recorded and contingent) represents the business value of the company.

10.3 Market-based Approach

This method, which is based on the market approach, determines the value of the business entity by comparing the subject company to (1) comparable firms (also called guideline companies) whose shares are publicly traded on organized capital markets (this method is also called the capital market approach or the comparative company analysis) and/or (2) guideline companies that have been bought or sold during a reasonably recent period of time (the transaction or M&A method).

In either case, an appropriate sample of guideline companies is selected based on comparability criteria. Ideal guideline companies are those which are in the same industry as the subject company with comparable operations in terms of products, diversification, economic influences and size, among other factors. Usually a minimum of 6 to 8 guideline companies are required to create a meaningful sample for either the capital market or transaction approach.

For each firm in the sample of guideline companies, several value indications or pricing multiples are calculated. Examples of pricing multiples include price to earnings, price to cash flow and price to net assets value. After these multiples are calculated for each guideline company, an appropriate value is selected for the subject company based on a thorough analysis of the subject company's risk and financial characteristics compared to the guideline companies. This multiple is then applied to the appropriate financial data (e.g., earnings, cash flow) of the subject business.

The result of applying the valuation multiple to the subject firm's financial data results in a preliminary estimate of fair market value. Depending on the circumstances of the appraisal, this preliminary estimate then may be adjusted for other factors such as minority interest discounts, control premiums, country risk factors or for lack of marketability.

10.3.1 The Guideline Company Method

Main reasons to use the method:

- As part of the market approach, usually there is much more data on other guideline companies, comparable to the Subject Company then there is data for the transaction approach and the data is more reliable.

Main reasons to reject the method:

- Typically, the guideline public company method is most useful when valuing minority interests (it is not the case for TEC where the purpose of this valuation is for a 100% controlling interest)

- The purpose of the Guideline Company Method is to develop value measures based on prices at which stocks of similar companies are trading in a public market. The comparable companies with TEC in Central and Eastern Europe do not have their shares actively traded on local stock exchanges and the only comparables existent are companies with larger revenues, with more diversified operations, functioning in well established markets and economies which are very different then the ones of Central and Eastern Europe.

10.3.2 The Transaction Method

Main reasons to use the method:

- The privatization process of electricity producers in countries from Central and Eastern Europe lead to several acquisitions of similar companies to TEC.

Main reasons to reject the method:

- In regards to the private company transaction method, the information availability is often sketchy and incomplete. Moreover, information related to these transactions can be misleading because economies of scale and synergies, which are considered in a buyer's analysis, are difficult or impossible to calculate based on historical public information.

11. Appendix 3 - Market Overview

11.1 Romania - Country Profile

11.1.1 Geographical Overview

Romania is situated in the South - Eastern part of Central Europe, with a frontier of 3,185 km that separates it from Hungary and the former Yugoslavia (W & SW), Bulgaria (S), the Ukraine and the Republic of Moldova (NE & E). It covers a surface of 238,391 sq km (4.8% of Europe), and has a population of 21.7 million.

11.1.2 Political Situation

Romania launched the negotiations for accession to the European Union, in February 2000. Within this process, the Romanian Government has committed to take the necessary steps in order to adopt a set of "European standards" formalized into 31 chapters called generically the *acquis communautaire*.

Romania closed all the negotiation chapters with the EU in December 2004 and signed the Accession Treaty in April 2005 in Luxembourg with the scheduled accession date set for January 1st, 2007.

In 1993, Romania had its Most Favoured Nation Status with the United States restored on a permanent basis and it joined NATO in 2004.

11.1.3 Main Macroeconomic Indicators

The figures characterizing the most recent evolution of the main economic indicators in the Romanian economy are summarized in the following table:

Table 33. Selected Macroeconomic Indicators of Romania between 2001 - 2004

	2001	2002	2003	2004
Population (million)	22.43	21.69	21.7	21.7
Nominal **GDP** (US$ billion) – current prices	39.7	45.7	55	73.2
Real **GDP growth** (% change)	5.3	4.9	4.8	7.2
GDP per capita (US$)	1,770	2,107	2,535	3,373
Consumer Price Inflation (% annual change)	34.5	22.5	15.4	11.9
Year-end **exchange rate** (ROL per US$)	31,597	33,500	32,595	29,067
Year-end **exchange rate** (ROL per EUR)	27,881	34,919	41,117	39,663

Source: www.securities.com

In November 2004, Fitch assigned "investment grade" rating to Romania ("BBB-" with a "stable" outlook). The main reasons quoted by the rating agency were: continuous decrease in inflation rate, uninterrupted economic growth since 2001, expanding exports, significant progresses made in the privatization process (especially in the utilities sector), acceptable level of the foreign public debt, tighter financial discipline in the economy, consolidation of the currency reserves of the National

Bank of Romania to over EUR 10 billion, an ever stronger banking sector. In addition to the above, one major factor in Fitch's decision to upgrade Romania by two notches was the country's perspective of EU integration in 2007, which is seen as a supplementary insurance that the country will adopt the necessary economic policies to maintain its positive trend.

11.2 Overview of the Romanian Electricity Market

Romania closed the "Energy" chapter with the European Union in June 2004. The state commitments assumed in this chapter implied that energy prices would be set on market basis, certain key companies would be privatized, the electricity market would be fully liberalized and prices would gradually converge to EU levels.

Starting 2000, the liberalization of the Romanian electricity market has been initiated and guided by the principles of the EU Directives 96/92/EC and, subsequently, 2003/54/EC concerning common rules for the Internal Market in Electricity.

The Romanian regulatory authority for electricity and heat generation (ANRE) was set up in 1998, and has been tasked with creating and implementing an appropriate regulatory system to ensure the proper functioning of the electricity and heat markets.

In February 2000, 10% of the Romanian electricity market was open, allowing ten large industrial companies to select their electricity suppliers and granting electricity supply licenses to five independent electricity producers. In January 2005, the opening degree has reached 55%, with all companies exceeding 1 GWh of electricity consumed in 2004 being declared eligible. The timetable for liberalization of the Romanian electricity market was set by the Romanian government in a strategy paper issued in 2003 and entitled "The Energy Roadmap", which contains the energy policy of the country with projections until 2015.

Table 34. Timetable of Liberalization of the Romanian Electricity Market

1 Jan 03	31 Dec 03	31 Dec 04	31 June 06	1 Jan 07	1 July 07
33% (40 GWh)	40% (20 GWh)	55% (1 GWh)	80%	100% industrial consumers	100% domestic consumers

Source: Road Map for Energy Sector in Romania

Presently (as of January 2005), the electricity wholesale market has two components: a competitive market and a regulated market.

The regulated component attempts to ensure, during the period of transition to a fully liberalized market, reasonable revenues to power producers and suppliers, given a unique level of tariffs at national level, for all captive consumers. ANRE establishes both the quantities and the tariffs included in the regulated (or portfolio) contracts between producers and the suppliers of captive consumers.

The key features of the competitive market in Romania are:

- **Bilateral, freely negotiated contracts** between the generating companies or suppliers and eligible consumers. Within the competitive market, the eligible consumers, the power suppliers and the power generators are able to buy and sell electricity at freely negotiated prices (both through contractual agreements and on the spot market);

- **Day ahead** market transactions; and
- **Export** contracts directly negotiated by electricity generators and/or suppliers with foreign customers.

Access to both the transmission and distribution networks is regulated. Tariffs are approved by ANRE and are published in the Official Gazette of Romania. Existing and new market participants are treated on a transparent and non-discriminatory basis.

11.2.1 Key Players on the Romanian Electricity Market

GENERATION

The table below provides a breakdown of the total electricity generating capacity in Romania:

Table 35. Main Players on the Generation Segment of the Romanian Electricity Market

	Approximate (gross) capacity (MW)
THERMAL POWER	
Turceni Energetic Complex	1,990
Rovinari Energetic Complex	1,320
Electrocentrale Bucuresti SA (several power plants)	2,938
Electrocentrale Deva SA	1,260
Termoelectrica SA (several power plants)	2,237
Several small co-generation thermal power plants under the administration of local municipalities	1,920
HYDRO POWER	
Hidroelectrica SA	6,000
NUCLEAR POWER	
SNN	707
Other producers	300
TOTAL	**18,672**

TRANSMISSION

The Transmission System Operator for the high voltage transmission grid (i.e. voltage higher than 110kV) is Transelectrica. The company operates according to the transmission and system operator licenses granted by ANRE and the transmission grid code.

SUPPLIERS

As of January 2005, ANRE had issued over 70 licenses for electricity suppliers. The suppliers resell the energy purchased from domestic producers or from importers to the final consumers. The only suppliers for captive consumers are the 8 regional distribution and supply subsidiaries of Electrica (the former national electricity distribution and supply company). However, once the market is fully liberalized, in the spirit of Directive 2003/54/EC, the electricity supply and distribution activities can no longer be performed by one single legal entity. The regional distribution and supply

companies will be replaced in their capacity as suppliers by the so-called "suppliers of last resort" in order for the electricity needs of the remaining small captive consumers to be covered.

DISTRIBUTION

As of July 2004, ANRE had issued 21 licenses for electricity distribution. Of these, eight were to the incumbent regional distributors. These distribution companies are responsible for the operation and maintenance of the distribution systems with a voltage lower or equal to 110 kV. The remaining distribution licenses have been primarily issued to companies operating at a local level supplying industrial areas.

The eight incumbent regional distributors are currently in the process of privatization. Electrica Banat and Electrica Dobrogea, went private in June 2004 (by a contract signed with Enel). It is expected that by February 2005, the privatization process for Electrica Moldova and Electrica Oltenia will also be finalized, the preferred bidders being E.ON and, respectively, CEZ. Electrica Muntenia Sud was announced to be the next offered for privatization, during 2005.

COMMERCIAL OPERATOR

The commercial operator of the electricity market is OPCOM, a legal entity and subsidiary of Transelectrica SA. OPCOM is responsible for the administration of commercial transactions in the electricity market.

12. Appendix 4 - Description of CE Turceni

12.1 Background Information

The Turceni Energetic Complex was set up in April 2004 through the merger of the "Electrocentrale Turceni" thermal power plant ("Turceni TPP") and three lignite mining exploitations – Jilt Nord and Jilt Sud open pits and Dragotesti underground mine ("the coalmines") – which were removed from the patrimony of the National Lignite Company "Oltenia" Targu Jiu.

The core activity of the Turceni Energy Complex is electricity generation. Other activities are: heat generation and supply of system services.

The merger between the TPP and the mining exploitations took place based on a Governmental Decision stipulating that the social capital of the Energetic Complex would be a sum of the social capital of the "Electrocentrale Turceni" TPP and that pertaining to the Jilt mining exploitation and the Dragotesti mine.

The Turceni TPP is the largest in Romania with an installed capacity of 2310 MW (7 x 330 MW installed power, an eighth unit never accomplished – investment abandoned) and a current operational capacity of about 1260 MW. The units have been commissioned during a period from July 1978 (unit 1) to November 1987 (unit 7).

The plant output is evacuated to the national power system via transformers of 24/400 kV and 4 lines of 400 kV (each line for two units), towards the system substation of Tantareni, situated several km away. For reserve power supply of internal consumers, the plant is supplied via 6 lines of 110 kV (3 substations of 110/6 kV).

The main fuel is lignite with a low heat value of 1400-1800 kcal/kg, supplied by train from distances averaging 35 km, the plant operating an unloading and storage system with a capacity of about 1 million tones (about 30 days of nominal consumption). The plant is supplied by train with heavy fuel oil (start-up fuel) from different sources and uses as main support fuel the gas extracted from a well belonging to Petrom and with a direct pipeline to the plant.

The cooling water is ensured from the Jiu river, mixed with water from 7 cooling towers with natural draught. Ash and slag are evacuated by hydraulic transport to the Valea Ceplea deposit with a storage capacity of about 18 million m^3 and a reserve in a second deposit of about 8 million m^3. On the water inflow towards the plant, a micro Hydro Power Plant has been installed, with an installed output of 10 MW.

The power plant split from Termoelectrica and completed its restructuring process in April 2003 by setting up a separate legal entity entitled SC Electrocentrale Turceni SA.

Prior to the merger with the coalmines, Turceni TPP held a 30-year authorization from the electricity regulator (ANRE) for the operation of 1,650 MWe electricity and 68.64 MWt heat cogeneration facilities conferred in 2003. It was also the holder of an 8-year electricity supply license and a 25-year electricity generation license both issued by ANRE in the same year. After the setting up of the Complex, in 2004, ANRE canceled the electricity generation and supply licenses and issued replacement licenses in the name of the newly created Turceni Energy Complex.

The coalmines EMC Jilt Nord, EMC Jilt Sud, and EMS Dragotesti were previously under the management of the National Lignite Company of Oltenia (CNLO, *Compania Nationala a Lignitului Oltenia*) Tg. Jiu. In accordance with Government Decision 103/2003, CNLO Tg. Jiu was restructured and, among other restructuring measures set forth in the legislation, the three coalmines, facilities and equipment were transferred to the newly set-up Turceni Energy Complex.

The combined annual production of the three mines is around 5 million tons of lignite with sales of the mining product mainly to Turceni TPP, located at approximately 30 km Southeast of the mines.

According to GD 103/2004 regarding the restructuring of lignite-based heat and electricity generation, which provides for the setting up of Turceni Energy Complex through the merger between Turceni TPP and the coalmines, the associated railway transport facilities were supposed to be included in the Complex. However, to the date when the present valuation was performed, no entries regarding such transport facilities had been made in the accounts of TEC.

13. Appendix 5 - Overview of Industry and Privatization in CEE

13.1 An Energy and Coal Industry Overview of Selected Countries in CEE

13.1.1 Poland

13.1.1.1 General Information

The Republic of Poland is situated in Central Europe and has a population of approximately 38 million.It is bordered by Russia, Lithuania, Belarus, and Ukraine to the east, the Czech Republic and Slovak Republic to the south, Germany to the west, and the Baltic Sea to the north.

The main macroeconomic indicators of Poland are listed in the table below:

Table 36. Poland – Selected Macroeconomic Indicators

	2001	2002	2003	2004
Population (million)	38.64	38.61	38.19	38.17
Nominal GDP (US$ billion) – current prices	183.03	188.63	206.92	241.8
Real GDP growth (% change)	1.0%	1.4%	3.7%	5.3%
GDP per capita (US$)	4,562	4,882	5,418	6,335
Consumer Price Inflation (% annual change)	5.5%	1.9%	0.8%	3.5%
Year-end exchange rate (zloties per US$)	4.09	3.84	3.74	2.99
Year-end exchange rate (zloties per EUR)	4.02	4.02	4.71	4.07

Source: www.securities.com

Poland joined the Organization for Economic Co-operation and Development (OECD) in 1996; in 1998 it became a member of the North Atlantic Treaty Organization (NATO) and in May 2004 it was one of the 10 countries that became members of the European Union.

13.1.1.2 Energy Industry Overview

13.1.1.2.1 Brief Description of Recent Developments

The stated guiding objectives of the measures adopted in the Polish power sector during the past decade have been to create a competitive energy market through the privatization of the energy industry and to attract the investments necessary for industrial modernization and environmental protection.

In 1996, Poland's cabinet decided the setting up of an independent energy regulatory authority and to allow third party access to the Polish electricity transmission grid.

Energy market liberalization in Poland started in 1998, when the country adopted a new energy law under which large electricity consumers (over 500 GWh annually) could negotiate directly with

power generators. It was compulsory for the Polish Grid Company – Polskie Sieci Elektroenergety (PSE) – to provide transmission for all buyers and sellers if technically feasible.

The schedule for phasing in third party access that started in 1997 with the largest users will eventually allow all customers to choose their electricity suppliers by 2005. The electricity liberalization timetable for Poland is as follows:

- 1998 was the start of third party access covering customers with annual purchases of over 500 GWh per year. This included 21 industrial customers and all the electric distribution companies. The 1998 coverage was 21% of all electricity consumption.
- On January 1, 1999 the floor was lowered to 100 GWh, increasing coverage to 83 customers constituting 36% of total consumption.
- On January 1, 2000, the floor was lowered to 40 GWh, increasing coverage to 179 customers constituting 43% of total consumption.
- On January 1, 2002, the floor was lowered to 10 GWh, increasing coverage to 610 customers constituting 51% of total consumption.
- On January 1, 2004, the floor was lowered to 1 GWh, increasing coverage to 3,296 customers constituting 59% of total consumption.
- On January 1, 2005, the market was fully liberalized, including all industrial and household consumers.

In December 1999, the Gielda Energii SA was established to set up an energy exchange in Poland. The company is a consortium of several energy companies, including Endesa of Spain. The Polish Ministry of State Treasury holds 22% of the shares. The Polish energy exchange started operation - including physical delivery and settlements - on July 1, 2000. The goal of the exchange was to overtake some of the power output that was being sold through long-term contracts (so-called KDTs).

By the years 2000, the issue of long-term contracts had become a crucial point in Poland's negotiations with the EU, as the persistence of this type of agreements was stalling the market liberalization process. KDTs were signed in 1994 – 2001 by power producers and the power grid company, Polskie Sieci Elektroenergetyczne (PSE) and oblige PSE to receive fixed amounts of energy for elevated prices, with some of the contracts covering periods until 2020. As of 2003, KDTs covered approximately 60% of the electricity supplied to the grid and had already been used by producers as guarantees for bank loans amounting to approximately USD 4 billion.

Despite repeated attempts of the government, resolution of the issue has been delayed several times because of lingering negotiations with power producers, particularly those with foreign investors as shareholders. Foreign companies have been protesting against elimination of KDTs, because the contracts guarantee power prices and stable revenues for many years. Some of them claimed they had invested in Poland only because of KDTs and complained that the government lacked a clear development strategy for the energy market, which did not allow then to make any long-term prognoses. Major foreign investors in Polish energy include French EdF and SNET, Swedish Vattenfall, US-based PSEG, Germany's Energie Baden-Wurttemberg AG etc. Elimination of KDTs is also an issue of concern for the banks that have granted the loans collateralized with such contracts.

On the other hand, annulment of KDTs is the main condition for allowing free development of the power sector in Poland and the sector's liberalization. On its part, the power grid company issued several warnings that if KDTs were maintained, it would face the risk of going bankrupt, as it would not be able to buy and pay for the contracted energy. As a consequence, power plants could lose liquidity and go bankrupt as well.

In 2003, the Polish cabinet prepared a draft law for KDT elimination, in which it proposed a possible solution to the problem. First of all, the law provided for placing a special 10 – 15-year bond issue, the proceeds of which would be used by power plants to repay the loans taken with KDT collateral. Furthermore, if the draft law were to be adopted, power producers would be offered compensations for the contracts' annulment with money raised through the issue. Practically, the amount of compensation proposed by the government was the difference between the value of the company with and without KDT. However, investors were dissatisfied with the proposed settlement as they also claimed compensations for the already made investment and opportunity losses.

In early November 2003, another obstacle to KDT annulment appeared, after the Polish European Integration Ministry declared that Poland would have to obtain approval from the European Commission before adopting the law on the elimination of the contracts, because it contained elements of public aid.

In January 2004, the Council of Ministers adopted the long-discussed draft law, but its implementation is still pending. The consensus finally reached by government and power plants was that the amount of compensations would not be set by law, but by the Energy Regulatory Authority separately for each power plant.

Currently (November 2004), the issue of KDTs is still under talks, as the European Commission is conducting investigations in order to determine whether the compensations offered by the government to power plants can be considered public aid.

Another key point in Poland's negotiations with the EU with regard to the energy sector was the environmental issue for which the country won two transition periods to be applied after its accession. Under the agreement concluded in the Accession Treaty, all Poland's power and CHP plants will have to meet the EU requirements concerning dust emissions in 2017, sulphur-dioxide emissions in 2015, and nitrogen-oxide emissions in 2017. The Polish power plants will also have a right to public assistance amounting to up to 50% of the investment outlays necessary to meet EU norms. It is estimated that thanks to these transition periods Polish power plants could save as much as USD 4 billion, which otherwise would have to be invested by the end of 2008 to meet EU environmental standards.

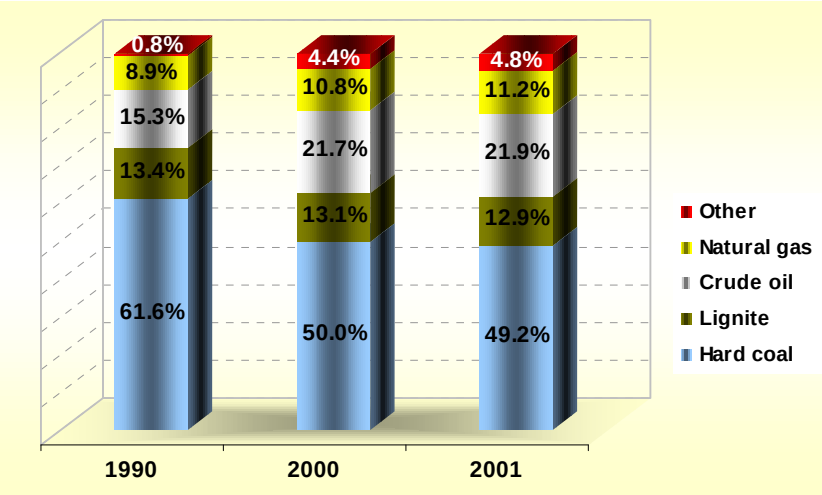
The privatization process was marked by the existence of KDTs, which were a decisive factor in choosing the Polish power sector for many of the interested investors. Furthermore, the generous transition periods, as well as the right to public assistance for meeting EU environmental norms, relieved a serious burden from the power plants' short and medium term investment plans. The evolution of privatization in the Polish power sector, which was quite slow during the first decade after 1989 due to the frequent changes in strategy made by the government, has almost completely been brought to halt in the period 2001 – 2004, since focus was shifted towards KDT resolution by a major bond issue and vertical consolidation of the sector.

13.1.1.2.2 Profile of the Electricity Sector

PRODUCTION

The most significant feature of the Polish power sector is its heavy dependence on coal as a primary resource. One of the strategic priorities of this country in recent years has been the diversification toward natural gas, oil and other resources, but, on the medium term, coal is expected to remain the dominant fuel, particularly in the electricity generation field.

Chart 1. Primary Sources for Energy Production in Poland (%)



Source: www.securities.com

Annual electricity consumption in Poland for the past decade has averaged about 120 TWh, of which about 63% goes to the industrial sector (including the energy industries).

Nearly 16 TWh is generated annually from district heating CHP plants. Overall, more than 15% of Poland's total electricity generation is generated in conjunction with heat.

Table 37. Electricity Generation and Consumption in Poland, 1990-2001 (in TWh)

	1999	2000	2001
Net Generation	132.2	135.2	135.0
hydroelectric	2.1	2.1	2.0
geo/solar/wind/biomass	0.5	0.5	0.6
conventional thermal	129.6	132.6	132.4
Net Consumption	118.0	119.4	118.8
Imports	3.5	3.3	4.3
Exports	8.4	9.7	11.0

Source: The US Department of Energy

13.1.1.2.2.1 Thermal Power

At the beginning of the years 2000, the Polish thermal power sector was structured as follows:

- The **electricity generating segment** – 54 power plants, including 5 lignite, 14 hard coal and 6 hydroelectric. 60% of the power plants were between 25 and 35 years old.
- The **heat generating segment** – including 250 heat-generating plants and nearly 230 combined heat-power plants (CHPs);

The largest power and CHP plants by capacity in 1999 were the following:

Table 38. The Largest Power and CHP Plants by Capacity in 1999

	Installed capacity (MW)
Power Plants	
Belchatow	4,340
Patnow-Adamow-Konin (PAK)	2,738
Kozienice	2,725
Turow	2,070
Rybnik	1,720
CHPs	
EC Warszawskie	945
ZE Lodz	592
EDF Krakow	460
ZE Kogeneracja	387
ZE Wybrzeze	353

Source: www.securities.com

The sector is currently (as of November 2004) undergoing a process of vertical integration, whereby mines, thermal plants and distributors are being merged together in single entities.

As of November 2004 the two largest power conglomerates are BOT and PKE. BOT (Belchatow Turow Opole) received 69% stakes in the Belchatow, Turov and Opole power plants and Belchatow and Turow lignite mines from the Treasury Ministry.

PKE (Poludniowy Koncern Energetyczny), the second-largest producer of electricity in Poland, includes the power plants: Jaworzno III, Laziska, Lagisza, Siersza, Halemba, Blachownia, as well as heat power plants in Katowice and Bielsko-Biala.

Furthermore, the Treasury Ministry considers merging Elektrownia Kozienice with the Bogdanka coalmine as privatization procedures for both entities have failed in the past. The cabinet still has still not decided whether the newly formed entity will be offered for privatization or will be included in PKE.

As of November 2004, the vertical consolidation of the sector is in progress. It is still unclear what the market configuration and the main players in the sector will be when the process is concluded.

13.1.1.2.2.2 Hydroelectric Power

Poland generates only about the same amount of hydroelectric power as its smaller neighbour to the south, Slovakia.

Most of the hydroelectric power plants in Poland are located in the southern and western part of the country, and are owned and operated by the Pumped Storage Power Plants Company (PSPP), a separate joint-stock company that was established in December 1993 (though seven-eights of its stock continues to be held by the Polish Power Grid Company). As of 2002, PSPP had 23 hydroelectric and pumped storage power plants (except for the pumped storage facilities, all of them quite small) with a cumulative installed capacity of nearly 1,500 megawatts (MWe). PSPP has 85% of the pumped storage hydroelectric capacity in Poland and 74% of the total hydroelectric generating capacity. PSPP's hydroelectric power plants represent about 4.5% of the total installed electricity production capacity in Poland.

There are currently (November 2004) no plans for privatizing any of the hydroelectric plants.

TRANSMISSION

The transmission segment is fully controlled by the state-owned power grid company Polskie Sieci Elektroenergetyczne (PSE).

DISTRIBUTION

The distribution segment includes 33 companies responsible for dispatching electricity to end users.

13.1.1.2.3 Primary Energy Resources

13.1.1.2.3.1 Coal

The country has significant coal resources of high quality, with estimated recoverable reserves of 50.9 billion tonnes, of which approximately 20 billion are currently open for exploitation.

The coalmining sector, which, under the Communist regime, used to be one of Poland's flagship industries, suffered significant degradation with the economic transformations after 1989. By the year 2000, this industry had turned out to be a burden for the economy, with unprofitable, environmentally unfriendly operations.

Drastic reforms were launched in the recent years, leading to numerous mine closures, mass lay-offs and, consequently, a rise in profitability. However, production costs remain high at many coalmines, resulting in the combination of the remaining operations into six coal companies and two coal holding companies (Katowici Holding Weglowy – KHW – comprising 8 coalmines and Kompania Weglowa – which took over 23 coalmines).

The historical summary of coal production and consumption in Poland is shown in Table 39:

Table 39. Coal Production and Sales in Poland, 1995 - 2004

	1990	1995	2000
Output (mn t)	148.3	137.0	101.0
Domestic sales (mn t)	116.5	99.1	78.0
Exports (mn t)	28.4	32.3	23.0
Average sale price (USD/t)	12.67	89.88	131.9
Average sale cost (USD/t)	18.51	93.59	129.5

Source: www.securities.com

The mining lobbyists claim that the industry's problems were caused by some political decisions made in 1989, when coal was declared as the chief energy source and, because its price influenced

significantly prices of nearly all other products (first of all electricity), it was maintained at an artificially low level for a number of years. This meant that the mining industry was excluded from the play of free market principles, which in turn resulted in accumulation of losses. But this situation was not the only factor. The international context also added to the fall of the mining industry in Poland. In the 1990s, coal prices dropped due to increased supply of coal from South Africa and Australia, where it was excavated cheaply in open pits. Polish exports of coal, which had been quite profitable before 1990, became increasingly subsidized. However, the unprofitable coalmines will be allowed to receive state assistance only until 2006 since the European Commission, which intends to drastically reduce coal production, wants the unprofitable mines in Poland to be closed by 2007.

In 2002, the government issued a privatization strategy for the mining industry. The first step envisaged was the regrouping of the seven mining companies into two or three new mining and coking concerns. The State Treasury would sell its majority stakes in the industry, while retaining the role of an administrator. This plan was also aimed at freeing the mines from the burden of debts to the Social Security Budget, the State Treasury and other state administration institutions.

It should be noted that the mining sector in Poland is still the beneficiary of elevated levels of subsidies. It is estimated that, during the period 1990 – 2001, the mining field received approximately USD 8.5 billion in public aid, despite of which, in 2001, the sector's debts amounted to USD 5.25 billion.

Restructuring and privatization of the mining sector has proceeded slowly due to opposition from trade unions and others. Nearly 100% of the Polish lignite mines are used by power plants situated in their immediate proximity and these power plants are the only use for Poland's lignite production. This is why the evolution of the lignite mining industry has been closely related to the evolution of the power plants

Privatization of Polish coal mines began in 2001 with an attempt to sell 45% of the Bogdanka mine to Management Bogdanka, a private company of investors. However, Management Bogdanka decided to withdraw from the deal after signing the privatization agreement. The mine was again offered for privatization in 2003, but the tender was annulled in 2004 due to lack of satisfactory bids. Current plans of the government do not exclude merging the mine with the Elektrownia Kozienice power plant and floating the newly created entity in the near future.

A privatization advisor was selected in January 2004 for Katowici Holding Weglowi (KHW). The mission of the selected consortium will be to work out analyses of KHW including Q4/2004, preparing a privatization strategy, as well as an appraisal of the mining holding company. The Treasury intends to sell at least 10% of the holding's equity through negotiations with an investor during the first half of 2005.

Privatization of Kompania Weglowa was postponed by the government for 2006.

13.1.2 Bulgaria

13.1.2.1 General Information

The Republic of Bulgaria is situated in South-Eastern Europe and has a population of approximately 7.8 million. It is bordered by the Black Sea to the east, Greece and Turkey to the south, Macedonia, Serbia and Montenegro to the west, and Romania to the north.

The main macroeconomic indicators of Bulgaria are listed in the table below:

Table 40. Bulgaria – Selected Macroeconomic Indicators

	2001	2002	2003	2004
Population (million)	7.89	7.84	7.81	7.78
Nominal GDP (US$ billion) – current prices	13.56	15.56	19.97	24.18
Real GDP growth (% change)	4.1	4.5	4.5	5.6
GDP per capita (US$)	1,719	1,984	2,553	3,107
Consumer Price Inflation (% annual change)	4.8	3.8	5.63	6.15
Year-end exchange rate (levs per US$)	2.22	1.88	1.55	1.44
Year-end exchange rate (levs per EUR)	1.96	1.96	1.96	1.96

Source: www.securities.com

Bulgaria achieved membership into NATO in 2004. In June 2004, it completed accession negotiations with the European Union; it is expected that EU membership will be granted on January 1, 2007.

13.1.2.2 Energy Industry Overview

13.1.2.2.1 Brief Overview of Recent Developments

The first detailed attempt in developing a national energy policy and strategy occurred in the late 1990s, and was outlined in the 1998 document, the "National Strategy for Development of Energy and Energy Efficiency Till 2010". Among others, this plan called for construction of 1,500 MW of coal-fired generating capacity, 430 MW of hydroelectric power with a pumped storage plant, and the restructuring of the Bulgarian state-owned vertically integrated monopoly electricity company, Nationalna Elektricheska Kompania (NEK), to improve the economy of its operations.

This energy strategy was updated in 2002 by the Bulgarian Ministry of Energy and Energy Resources, incorporating Bulgaria's intention to proceed with various privatizations that would move the country toward a free market. At that moment, there were more than 100 state-owned energy companies in Bulgaria, and the revised strategy envisioned eventually selling about three-quarters of them. Energy prices were to be raised toward market levels. Similar price increases were

envisaged for district heating. The revised Energy Strategy also strengthened the autonomy of the State Commission for Energy Regulation (SCER), set up in 1999.

As called for in the Energy and Energy Efficiency Act of July 1999, the Bulgarian energy sector was reorganized in 2000. Seven power generating companies (6 TPPs and Kozloduy NPP), a transformed NEK, and seven distribution companies were established from the former NEK. As of November 2004, NEK is the government-owned monopoly transmission and dispatch company. NEK has monopoly rights on power exports and imports until the end of 2006 and will retain full control on the high-voltage network.

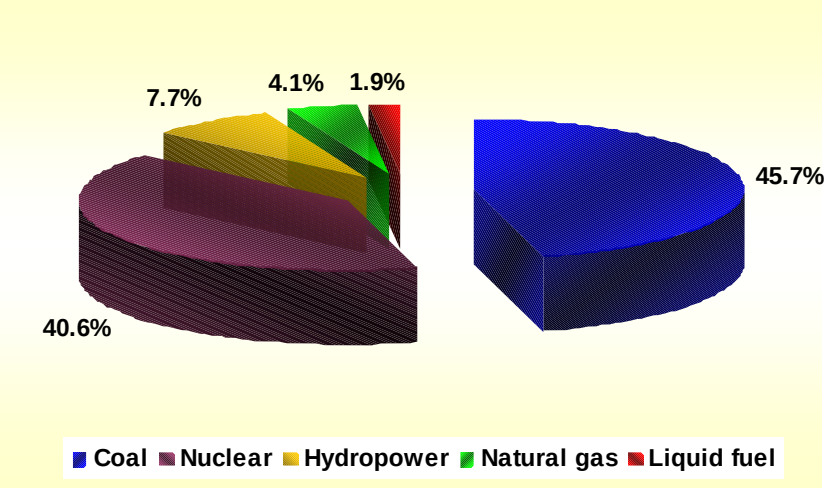
The next phase of reforms includes privatization of power units and gradual introduction of third party access by licensing large industrial consumers to sign deals directly with power producers. The process was initiated in 2003 when companies with annual consumption exceeding 100 GWh per year and no liabilities to NEK were allowed to negotiate power prices directly with producers. The Energy Ministry estimates that, as of November 2004, some 22% of the electricity supply is open for direct price negotiations with power producers. The ratio is expected to grow to 25% in 2005, 28% in 2006 and to cover all industrial consumers in 2007 (some 60% of the local demand). Power supplies arranged with contracts between producers and industrial consumers pass through the network of NEK at fixed fees controlled by the State Commission for Energy Regulation (SCER).

13.1.2.2.2 Profile of the Electricity Sector

PRODUCTION

Bulgaria has an estimated total gross capacity of 13,130 MW, with thermal power plants making up approximately 45%, Kozloduy power plant about 40% and hydro capacity almost 10% of this capacity. Most of the generating capacities were built in the 1960 – 1980 and the sector needs considerable investments in order to remain competitive. The country is a net exporter of electricity covering about 70% of the power deficit in the SE Europe region (Turkey, Greece, Serbia & Montenegro, Macedonia, and Albania).

Chart 2. Electricity Production Structure in Bulgaria as of 2003



Source: www.securities.com

13.1.2.2.2.1 Thermo-power plants

The total capacity of all thermal plants in the country is estimated at 6,700 MW, but less than 50% of it is utilised. Some 54% of the power capacities in the sector are based on locally extracted coal, 21% on imported coal and the other 25% rely on imported oil and natural gas.

Table 41. Major Power Plants in Bulgaria as of 2004

Power Plant	Fuel Type	Capacity (MW)	
		Unit Capacities	Total
NPP Kozloduy	Imported uranium	2 x 440 2 x 1000	2,880
TPP Maritsa East I	**Local lignite**	**4 x 50**	**200**
TPP Maritsa East II	**Local lignite**	**4 x 150 2 x 210 2 x 215**	**1,450**
TPP Maritsa East III	**Local lignite**	**4 x 210**	**840**
TPP Maritsa 3	**Local lignite**		**120**
TPP Varna	**Imported black coal**	**6 x 210**	**1,260**
TPP Bobov Dol	**Local brown coal**	**3 x 210**	**630**
TPP Rousse	**Imported black coal**	**2 x 30 2 x 110 1 x 60**	**340**
CHPs, autoproducers	Gas, fuel, coal		1,800

Source: www.securities.com; www.fe.doe.gov

In 2004, the Energy Ministry has launched privatization procedures for 2 of the abovementioned power plants (Varna and Bobov Dol) and several district heating companies with power generation capacities.

Public-private partnerships (PPPs) have been arranged for Maritsa East I and III TPPs, which use locally based lignite inputs extracted under open mining technologies. The two energy investment contracts were approved by the Bulgarian government in May 2001 with 2 American companies, AES and Entergy, for a total worth of USD 1.3 billion. Under these contracts, AES engaged to construct a new 670 MW capacity in Maritsa East I, while a joint venture between NEK and Entergy would be set up to rehabilitate the existing four capacities in Maritsa East III.

The completion of both deals, the negotiations for which had been held for almost four years, had been postponed for different reasons, notably state guarantees (the state refused to issue state guarantees for the projects but instead decided to pass comfort letters) and the price for which NEK would purchase electricity from the two plants under 2 power purchase agreements (PPAs) for 15, and respectively, 18 year-periods. The final version of the contracts envisaged that AES would sell the produced electricity to NEK at USD 45 per MWh but the price would be gradually lowered to USD 43 per MWh, while the price of the electricity from Entergy would be USD 30 per MWh. Both of the price arrangements would be valid until the transfer of ownership. The contracts would apply a BOO (build–operate-own) scheme and NEK would become the owner of the thermo-plants in a 15-year period in the case of AES (Maritsa East I) and 18-year period in the case of Entergy (Maritsa East III). The exploitation period of the plants would be 30-40 years. The technologies to

be applied according to AES's and Entergy's projects would decrease environment pollution by approximately 90%. The contracts would also pave the way to the German investor Rheinbraun, which manifested the intention to invest in the coalmines of Maritsa East basin, single supplier of inputs to the Maritsa East TPPs.

Initially, AES and Entergy announced it would take some six months to arrange the financing with the banks and the real work could start at end-2001.

For the construction of the 670 MW capacities at **Maritsa East I**, an estimated USD 850 million financing was deemed necessary. According to the contract, out of this amount, AES was expected to provide USD 225 million, while the remaining would represent loans from the US Overseas Private Investments Corporation, KfW and EBRD. The joint venture between AES (88%) and NEK (12%) received a conditional license from the State Commission for Energy Regulation in July 2002. The license would come into force when AES verified that the necessary financing for the project was secured, as well as the land ownership of the site where the new power plant was to be built. By September 2002, suspicion had spread that AES was facing financial difficulties and would not be able to honour its obligations in the Maritsa East I contract. It was rumoured that AES was in talks with the Enel Produzione regarding the possibility that the Italian company may join the JV. In April 2003, the necessity of constructing a new generating unit became uncertain due to Turkey's sudden decision of interrupting electricity imports from Bulgaria. However, the government decided to proceed with the deal and, in an attempt to unblock the situation, prepared a letter of political support for the modernization of Maritsa East I to the satisfaction of Enel Produzione which, in exchange, would acquire the 12% stake of the off-shore company 3C, a subsidiary of AES in the project. By November 2004, the deal had not yet been concluded. The conditional license expired without being made avail of. The project is three years behind schedule. AES has repeatedly reaffirmed its commitment to the transaction estimating that it would be launched some time in 2005.

For the modernization of the **Maritsa East III** capacities, an estimated USD 450 million financing was deemed necessary. The joint venture set up for this purpose, in which Entergy held 51% and NEK 49% stakes was issued a 20-year license in February 2002.

In February 2003, Entergy announced that the JV sealed the financial agreements with foreign and local banks for loans totaling EUR 348 million.

In May 2003, Enel Produzione (a wholly owned subsidiary of Enel SpA) acquired 60% of Entergy's share in the JV that was set up to run the Maritsa East III project, with an option to increase its stake to 100% depending on the future financial results from the partnership. The Italian company joined the rehabilitation project through a capital increase of the JV. After the capital increase, NEK's share fell to 27%, Enel Produzione had a 44% participation and Entergy held the remaining 29%.

Although rehabilitation works are lagging behind schedule, the upgrade of one of the units has been finalized. After its switch to the power grid, the other three units will be modernized successively

In April 2003, Japanese Mitsui signed a contract to carry out the rehabilitation of four of the olderunits of **Maritsa East II** TPP. The project costs, estimated at EUR 290 million, were secured, in part, by the Japanese Bank for International Cooperation. One of the conditions imposed by this institution was that no change in state ownership of the TPP would occur until 2008.

As for **Maritsa 3** TPP, 49% of its shares were purchased by First Investment Bank in April 2003 for an estimated value of EUR 4.5 million. The shares were subsequently acquired over the Bulgarian Stock Exchange by a local company, Top Group Sofia. Transfer from First Investment Bank to Top Group was concluded in May 2003.

A key aspect in the negotiations for EU accession with relation to thermal power generation is represented by the obligations of Bulgaria under the "Environment protection" chapter. It was estimated that approximately BGN 1.27 billion (4% of the country's GDP) should be invested in installations for control of emissions from TPPs according to EU environmental directives. The burden of such expenses is an especially difficult task due to the fact that an approximately equal amount was estimated as necessary for projects of replacing outdated capacities at the TPPs. Longer transition periods were set for the modernization and the construction of sulfur processing installations at some TPPs, as the plants will work with lower power capacity during the upgrade. Varna and Rousse TPPs should meet environmental requirements by 2016. Most probably, Bobov Dol and Maritsa 3 TPPs will stop functioning by 2018, as building sulfur processing facilities at these plants was not deemed economically effective.

13.1.2.2.2.2 Nuclear Power Capacities

The NPP in Kozloduy, 200 km to the north of Sofia on the Danube River, is operating with 4 units (3,4,5 and 6), securing 40.6% of the country's power supply in 2003. It is the largest NPP in the Balkan Peninsula and it totals 6 units using the Russian-designed VVWE reactors. International concern about the plant's safety recordturned the decommissioning of units 1,2,3 and 4 into a key point in Bulgaria's negotiations for EU accession. According to government commitments during this process, Units 1 and 2 have been decommissioned on December 31, 2002, whereas Units 3 and 4 should be closed by the end of 2006. The decision to close two units was not popular with many of the country's residents, as there is great concern that it could lead to higher electricity prices, or in the worst case, power rationing. In support of continued operation of the remaining units, government observers have noted a marked improvement in safety at Kozloduy due to training, new investment, and a marked increase in employee morale.

The government has recently announced plans to re-launch investments in a new nuclear plant in Belene and holds talks with 3 international consortiums. The process will start with a major contractor in the project, which has been frozen 15 years ago, after about USD 1.5 billion had been expensed will be selected in the near future. The new plant is planned to start operations in 2010. The State will retain control stakes in the nuclear facilities through NEK.

13.1.2.2.2.3 Hydro-power plants

The total capacity of more than 80 hydro-power plants operating in the country is estimated at 2,700 MW at the end of 2003. The plants however, have generated only 7.7% of the power production in 2003 with a capacity that is comparable to that of the nuclear sector. The large power storage hydro-power plants are used only for balancing the national electricity system and are operating only in emergency cases.

Following unbundling and privatization procedures in the electricity sector, private companies own and operate all small hydropower facilities. The state keeps full control in 14 large hydro-power plants which account for about 86% of the total hydro-power generation in the country. The sector appears attractive for new investments, as a new small private plant has been launched in 2004 and several other projects are under way, including a EUR 220 million investment run by Austria's VA Tech Hydro.

TRANSMISSION

The transmission operator is the state-owned NEK (National Electricity Company of Bulgaria) which has monopoly rights on power exports and imports until the end of 2006 and maintains full control on the high-voltage network.

DISTRIBUTION

The retail power supply network is managed by 7 distribution companies united in 3 geographical groups: Western group, Southeast group and Northeast group.

Table 42. Structure of the 7 Power Distributors of Bulgaria Grouped in 3 Packages

	Sales in 2003		Subscription contracts	
	EUR million	**Share of total**	**No. (million)**	**Share of total**
Western Group	345	40.5%	1.9	41.8%
Southeast Group	215	34.2%	1.5	33.1%
Northeast Group	291	25.2%	1.1	25.2%
Total	**851**	**-**	**4.5**	**-**

The government has finalized the privatization process for the 3 groups in October 2004. The new owners of the power retailers are: Austria's EVN, the Czech Electricity Company – CEZ and Gemrnay's E.ON. They have agreed to pay a total of EUR 693 million for 67% stakes in all companies, an amount that has exceeded market expectations by roughly two times. For more details regarding the privatization of the 7 Bulgarian distributors, please refer to Chapter 13.2– "An Overview of the Privatization Process of the Power Sector in Selected CEE Countries".

13.1.2.2.3 Primary Energy Resources

Bulgaria has no domestic oil resources and only small proven reserves of gas, and is relying on nuclear and thermal power for much of its electricity supply.

13.1.2.2.3.1 Coal

RESERVES

There are large deposits of low-quality brown coal in Bulgaria. Estimated reserves include about 3.0 billion metric tons of lignite and 200 million metric tons of sub-bituminous coal. The largest deposit is the Maritsa coalfield in southern Bulgaria; with coal that has a relatively high ash and sulfur content. At current production rates, the reserves at Maritsa are projected to last about 50 years.

PRODUCTION AND CONSUMPTION

Most of the coal consumed in Bulgaria is used for power production. Bulgaria will probably remain a net coal importer, as a supply of higher-quality hard coal is necessary for metallurgical industries. This coal is obtained from as near as Ukraine and as far away as Australia.

An historical summary of coal production and consumption in Bulgaria is shown in Table 43.

Table 43. Coal Production and Consumption in Bulgaria, 1998-2002 (in millions of short tons)

	1998	**1999**	**2000**	**2001**	**2002**

	1998	1999	2000	2001	2002
Production	33.19	27.89	29.14	29.37	28.40
Anthracite	0.03	0.03	0.02	0.01	0.01
Bituminous	0.07	0.11	0.11	0.15	0.15
Lignite	33.09	27.75	29.01	29.21	28.25
Consumption	36.86	31.89	32.24	34.68	32.40

Source: The US Department of Energy

MINING

Bulgaria's coalmines with the largest production rates are the Maritsa East Mines, which feed 2,490 MW of mine-mouth power plants (Maritsa East I, II and III TPPs, as well as the Maritsa 3 TPP and the Briquette factory). In recent years, 23.8 million tons of lignite have annually come from these mines, including about 3 million metric tons per year that is used for the production of briquettes for household use. There is a goal to increase the output of the Maritsa East Mines to pre-1989 levels in the 2005-2010 time frame. This includes developing the Troyanova-1, Troyanova-2, and Troyanova-3 mines at the Maritsa East basin. In order to carry out the investments for rehabilitation and environment protection required by such ambitious plans, in 2000 a JV company was set up by the state with German-based RWE Rheinbraun. The stakes in the JV were set to 33% for the State and, respectively, 67% for the German investor. After three years of negotiations, in 2003, RWE Rheinbraun was selected as strategic investor in the privatization of Maritsa East Mines. The total investments committed by Rheinbraun in the Maritsa East Mines amounts to EUR 200 million.

Other mines in Bulgaria have much lower production rates. The Bobov Dol Mines, in southwestern Bulgaria, produce about 2 million metric tons per year of brown coal, which is used at the 630 MW Bobov Dol power plant. The Stanyantsi, Beli Breg, and Choukourovo Mines produce about 1.5 million metric tons of coal per year; most of this coal is also used at the Bobov Dol power plant. The Pernik Mines, west of Sofia, are depleting their deposits and will eventually be phased out. They have been supplying about 1.6 million metric tons of coal per year, mainly for the Republica power plant.

The Maritsa East Mines, Bobov Dol Mines and Pernik Mines are state-owned and sell coal at state-regulated prices to consumers. Majority stakes in Beli Breg, Choukourovo and Stanyantsi Mines were sold by the state during the years 2001 - 2002. In Bulgaria, there is heavy coal use for heating in the residential sector, although households are gradually switching to natural gas and electricity for heating. Much of the household coal heating is with briquettes, especially in the vicinity of the briquette factory (privatized in 2004) in Stara Zagora. About 9% of Bulgaria's coal production is used for making briquettes.

Besides these state-owned mines there are some coal mines that sell their products at contracted prices. The largest of these are the Pirin Mine, the Balkan Mine, the Cherno More Mine, the Vitren Mine, and the Anthra Mine. The Pirin Mine provides about 0.3 million metric tons of coal per year for the Bobov Dol power plant, but the costs at this mine will need to be reduced to attain profitability. The Balkan and Cherno More Mines annually produce 100,000 tones and 200,000 metric tons respectively, with their coal being used at the Sliven and Gabrovo power plants. The Vitren Mine produces 100,000 metric tons of coal per year, while the Anthra Mine produces 15,000 metric tons per year of anthracite. These mines are all expected to continue at about these same production rates.

COAL MARKET DEREGULATION AND LIBERALIZATION

In August 1998, the Bulgarian government issued its Action Plan for Coal Mining Companies for the Period 1998-2001. This plan indicated that inefficient mines would be closed over this period and then there would be free market pricing of coal and privatization. In 2000, Bulgaria had 26 operating mines, of which 13 were deemed to be viable.

Bulk coal and coal briquette prices used to be subsidized but the Bulgarian energy strategy adopted in 1999 called for phasing out the subsidies. By letting the prices of coal and briquettes rise to market levels the strategy expected competition to prevail and encouragement of investment in coal mining.

13.1.3 The Czech Republic

13.1.3.1 General Information

The Czech Republic has an approximate population of 10.3 million and is bordered by Poland to the north, the Slovak Republic to the east, Austria to the south, and Germany to the west.

The main macroeconomic indicators of the Czech Republic are listed in the table below:

Table 44. The Czech Republic – Selected Macroeconomic Indicators

	2001	2002	2003	2004
Population (million)	10.22	10.19	10.21	
Nominal GDP (US$ billion) – current prices	59.6	74.25	85.4	93.01
Real GDP growth (% change)	3.6	2	2.9	3.3
GDP per capita (US$)	5,831.7	7,286.6	8,369	
Consumer Price Inflation (% annual change)	4.7	0.6	0.1	2.96
Yearly average exchange rate (CZK per US$)	38.03	32.73	26.32	27.36
Yearly average exchange rate (CZK per EUR)	32.59	31.19	32.31	30.69

Source: www.securities.com

The Czech Republic became the first post-communist member of the Organization for Economic Cooperation and Development (OECD) in December 1995. In 1998 it became a member of the North Atlantic Treaty Organization (NATO) and in May 2004 it was one of the ten countries that adhered to the European Union.

13.1.3.2 Energy Industry Overview

13.1.3.2.1 Brief Overview of Recent Developments

OVERVIEW

The Czech energy market is being liberalized gradually. The process began in January 2003, when commercial customers consuming over 40 GWh of energy annually became free to choose their energy supplier. This led to a reduction in electricity prices by approximately 5 % during the first quarter of 2002 for this market segment, which has 65 eligible customers representing approximately 30 % of the Czech market. Electricity prices for households were raised by 9.9 % on average as of 1 January 2002, thereby broadly reaching cost recovery levels.

As of January 2003, commercial customers consuming 9 GWh and more annually became free to select their suppliers.

That same year, parliament amended the energy law to allow for the even more rapid liberalization of the sector. Companies with equipment measuring power consumption will be free to select their suppliers. In 2005, all customers with the exception of households will be free to do so, and as of 1 January 2006, so will households.

The Czech energy law allows the Czech government to influence the import of energy and gas to the CR until 2005, by which time most of the Czech energy market should be liberalized. Subsidies for household electricity were phased out in 2002.

The state also hopes to increase the share of renewable resources in overall electricity consumption from 1.5 % to as much as 6 % by 2010. In January 2001, CEZ announced it would be lessening its dependence on coal in the future, possibly mothballing its coal-fired generators. The power utility has also announced that the share of electricity produced by nuclear power plants will represent 31 % in 2003, compared to the current 17 %.

REGULATION

The sector is under the eye of the Energy Regulatory Office with a staff of 75. The regulator has made some important decisions concerning market rules, prices in captive market segments and electricity trade, and has issued a substantial amount of the above-mentioned implementing legislation. The regulator has arbitrated in several conflicts between companies active on Czech energy market and has licensed enterprises active on the Czech energy market.

CEZ

Ceske energeticke zavody (CEZ) is the dominant electric power utility in the CR. The company produces over 70 % of the country's electricity. It operates 28 power plants – 10 fossil fuel, 13 hydroelectric, two wind power, two nuclear, and one solar.

The Czech state owns 67.60 % of CEZ.

It has the capacity to produce 10,700 MWh of electricity.

CEZ holds majority stakes in the following regional distributors:

SEVEROCESKA ENERGETIKA (SCE)

CEZ owns a majority in the North Bohemian distributor SCE. The distributor's other shareholders are Envia Mitteldeutsche Energie AG (29.16 %), E.ON (5.92 %), and RWE (4.42 %).

SCE netted CZK 622 mln in 1H 2004, up by CZK 485 mln yr/yr, and its revenues from the sale and distribution of power grew by 11 % to CZK 6.05 bn.

SCE sold 3,394 mln MWh of power in Jan-June 2004.

SEVEROMORAVSKA ENERGETIKA (SME)

CEZ owns 59.08 % of SME, while EBO Czech Investment Limited owns 21.79 %.

SME generated a gross profit of CZK 859 mln in 1H 2004, up by CZK 35.018 mln from a year earlier.

SME sold 4,160.3 GWh of electricity in 1H 2004.

STREDOCESKA ENERGETICKA (STE)

CEZ owns 98 % of the Central Bohemian distributor STE. CEZ had talks about exchanging its stake in Prazska energetika (PRE) for RWE's 35 % of STE, but they failed in 2003.

STE netted CZK 510 mln in 1H 2004, a 27 % yr/yr increase.

Revenues grew by nearly 5 % to CZK 6.12 bn in Jan-June.

Electricity sales rose 0.44 % to 2,955 GWh.

ZAPADOCESKA ENERGETIKA (ZCE)

CEZ owned 50.3 % of the West Bohemian distributor ZCE then acquired an additional 34.4 % in a swap with E.ON.

ZCE saw its 1Q 2004 operating profit grow 30 % to CZK 653 mln, while its gross profit grew roughly 30 % to CZK 681 mln.

VYCHODOCESKA ENERGETIKA (VCE)

CEZ owns 99 % of the East Bohemian distributor.

VCE netted CZK 850 mln in 1H 2004, up 81 % yr/yr despite a 3 % drop in electricity sales to 3,001 GWh.

Sales were up almost 4 % at CZK 6.14 bn in 1H 2004.

OTHER REGIONAL DISTRIBUTORS:

The German energy concern E.ON swapped its minority stakes in Zapadoceska energetika (ZCE) and Vychodoceska energetika (VCE) to CEZ in return for minority stakes in Jihomoravska energetika (JME) and Jihoceska energetika (JCE). E.ON now controls over 80 % of both JME and JCE.

In August 2004, E.ON annonced it will set up a new distributor – E.ON Distribuce – to replace JME in Brno, South Moravia. It will also establish E.ON Energie to replace JCE in Ceske Budejovice, South Bohemia.

JIHOMORAVSKA ENERGETIKA (JME)

JME made a record CZK 1.065 bn profit in 2003 (latest available figures) and raised its net profit by over CZK 230 mln.

Sales grew to CZK 15.5 bn in 2003, from CZK 15.42 bn in 2003.

The company sold 8,652 GWh of electricity in 2003, up 7.6 % yr/yr.

JIHOCESKA ENERGETIKA (JCE)

JCE netted CZK 527 mln in 2003 (latest available figures) down by CZK 33 mln yr/yr.

Sales rose by CZK 185 mln to CZK 6.62 bn in 2003.

PRAZSKA ENERGETIKA (PRE)

The City of Prague acquired a 51 % stake in the Prague power utility PRE as part of a deal with Germany's GESO AG which had held 16.49 % of PRE. The deal, reached between the City and three German companies – RWE, Ruhrgas, and Geso – established three holding companies PRE Holding (electricity), PP Holding (gas), and PT Holding (heat). In each company, the city has a 51 % stake.

The power company CEZ sold its 34 % stake in PRE to the financial group J&T for CZK 4.4 bn.

PRE netted CZK 473.4 mln in 1H 2004, down 30 % yr/yr, but sales were up 8.7 % at CZK 5.49 bn.

PRE sold 2,695.1 GWh of electricity in 1H, up 7.2 % yr/yr.

OTHER PLAYERS

Producers

The largest electricity supplier in Prague apart from CEZ is the heat producer Prazska Teplarenska.

Elektrarny Opatovice, an East Bohemian power producer, accounts for 3 % of Czech power production. It owns and operates two major power plants (Melnik I and Opatovice) and sells power to CEZ under a negotiated contract.

Import/Export

According to the Czech Industry and Trade Ministry, three Czech firms are licensed to export electricity and six to import. Two firms dominate – CEZ and Czechpol. Czechpol is the major importer of electricity, bringing in over 50 % of all power imports in 1999 (a total of 1.4 TWh). It was bought recently by the U.S.-based Cinergy Global Power Inc., part of Cinergy Corp.

Nuclear power

The Czech Republic operates two nuclear power plants at Dukovany and Temelin. At the Dukovany NPP, four units of the VVER 440/213 type are in operation. At the Temelin NPP, two units of the VVER 1000/320 are currently in different stages of commissioning.

Test operations of the first reactor unit of the Temelin NPP were completed in June 2002 with full power operation attained. The unit is now undergoing trial operation, the last stage of commissioning prior to receiving a license for commercial operations. In June 2002, the self-sustaining fission reaction was initiated at the second reactor unit and test operations are ongoing in accordance with a license granted by the regulatory authorities.

INFRASTRUCTURE

The electricity transmission system in the Czech Republic includes an extensive array of transmission lines and substations. It consists of approximately 1,750 miles of 400 kilovolt (kV) lines and approximately 975 miles of 220 kV lines. Additionally, approximately 80 miles of 110 kV lines supply electricity to a well-developed 110 kV network.

The electricity transmission system is highly interconnected with the transmission systems of all neighboring countries. The Czech Republic is a member of the CENTREL association (along with

the Slovak Republic, Poland, and Hungary), whose members are working as a group to synchronize interconnections with the Western Europe UCPTE System.

13.2 Overview of the Privatization Process in Selected Countries of CEE

13.2.1 Poland

13.2.1.1 Brief History of the Privatization Process in the Polish Power Sector

The privatization process in Poland has been rather slow, mainly due to the frequent and somewhat chaotic changes in the privatization strategy brought by the two institutions governing the field: the Ministry of Economy and the Ministry of Treasury.

Initially, it was proposed that distributors be privatized ahead of producers and CHPs, then, in June 2001, it was decided that the privatization process for generating units should be accelerated, without altering the pace for distributors. The privatization methods adopted until the beginning of 2002 allowed investors to buy up to a maximum of 45% in the production entities and up to 25% in the power distributors. It was planned that the price for the supply segment would be deregulated, whereas transmission and distribution costs would still remain regulated.

A few weeks after the latest changes to the proposed method of privatization, the Ministry of Treasury presented a completely opposite strategy - vertical consolidation of the Polish power sector whereby producers, mines and distributors would be merged four or five massive production-distribution integrated units before being sold. The newly formed companies would then be listed and privatized through IPOs on the Warsaw Stock Exchange. Before 2002, privatization through the bourse had not been considered on a large scale. The motivation of this proposed method was that the Polish energy sector is highly dispersed and it was estimated that only companies with a market share of about 15% (at the time only a couple) would be able to operate in competitive terms on the European market.

In December 2002 however, the government decided to amend once more the strategy it had publicly announced at year half. Due to the repeated failures in the privatization attempts of several generation and distribution companies, the government's stance towards privatization of large power companies became more cautious. The new strategy provided for a complete halt in privatization of power distributors. In the production segment, which accounts for approximately 50% of assets in the Polish energy sector, the Treasury planned to maintain full control over the plants holding about 30% of the market. In the companies accounting for a further 30% of the market, the state was to be the major shareholder. All offers for privatization in this segment were put off until at least 2004. The transmission operator was to remain in the state's hands in the foreseeable future.

The government adhered to the above strategy for no more than a year as, during 2003, the privatization process in the energy sector was blocked. The general reason was deterioration of the investment environment in the global economy, coupled with a series of domestic factors, among which: the introduction of an excise tax on electric power, payable by power producers, the lack of a clear strategy for the sector and, the lingering uncertainty concerning KDTs (please refer to Chapter 13 – "An Energy and Coal Industry Overview of Selected Countries in CEE" - Poland). During 2003, the government of Poland withdrew from the few privatization tenders initiated for power plants, motivating that the offers were below expectations.

In 2004, the attention of the authorities completely shifted from privatization, which was upheld for 2005 – 2006, to vertical consolidation of the sector, in spite of objections from the Energy Regulatory Authority and to finding a resolution for the KDT issue. The process kicked off in April, a month before Poland's accession to the EU. Within this process, Belchatow-Opole-Turow and Polska Energia (comprising lignite mines, power plants and generation companies) power groups were created and consolidated and distribution companies were merged in groups of 5 to 8 companies and, wherever deemed necessary, integrated with power plants and CHPs. Vertical consolidation is currently (as of November 2004) in full progress and the privatization process is expected to pick up in 2006, when the newly created companies are planned to be floated on the bourse.

13.2.1.2 Privatization Transactions in the Polish Power Generation Sector[10]

Company	Investor	Stake put on sale	Capacity in MW	Date of sale	Price paid (in million) per stake
Power Producers					
PAK	*Elektrim (Poland)*	*38.5%*	*2,700*	*Mar 1998*	*USD 88. Elektrim declared will to buy 50%in PAK and take over lignite mines in Konin and Adamow. Elektrim has agreed with the Treasury Ministry on building a new unit – Patnow II. The deadline for investment conclusion was moved by 15 months to July 1, 2006.*
Rybnik	**EdF (France)/ Energie Baden-Wurttemberg AG (Germany)**	**90%**	**1,800** (approx. 8.3 TWh annual sales)	**Mar 2001**	**In May 2001, EdF and EnBW acquired 50% for USD 171.6 million. In Aug 2003 Treasury sold 15.8% for USD 51.5 million. In Dec 2003 the Treasury confirmed selling remaining 19.17% for USD 56.9 million. With the shares bought from employees the investor held, as of Nov 2003, 90% of the shares.**
Polaniec	**Tractebel (Belgium)**	**25% + 1 + 60%**	**1,695** (approx.7 TWh annual sales)	**Apr 2000Apr 2003**	**EUR 87.5 million / 25% + EUR 159.6 million / 60%. The investor promised to invest a total of EUR 339 million in Polaniec by 2013. Including the shares bought back from the company's employees, the investor holds 100%.**
Skawina	PSEG (USA)	63.4%	575	June 2002	USD 24.5 / 35%; under the privatisation deal, PSEG is obliged to invest USD 56 million until 2006. As of Nov 2003, PSEG held 63.4% and the Treasury had declared its intention of selling its stake in the nearest future.
Kozienice	-	Up to 85%	284.5	Cancelled	Offered for privatization in 2002. The privatization process failed; the Treasury considers merging the plant with the coalmine Bogdanka and floating the newly created entity. It is not excluded that the Treasury might give up the plan of making the power plant public and will include it in PKE, together with Bogdanka.

[10] As of November 2003. The table refers strictly to power generation plants (does nor include transactions involving CHPs).

Company	Investor	Stake put on sale	Capacity in MW	Date of sale	Price paid (in million) per stake
Ze Ostroleka	-	Between 10 and 85%	387.2	Cancelled	Offered for privatization in 2002. The privatization process failed, as the only bidder – Elektrabel – placed unsatisfactory offer; Treasury considers including plant in PKE (the second largest power conglomerate in Poland).
Ze Dolna Odra (ZEDO)	-	Up to 85%	1,957 (power) 750 (heat)	Cancelled	Offered for privatization in 2003. The process failed. Treasury might renew efforts to sell it. In previous tender the only bid was placed by Electrabel. Treasury does not exclude including ZEDO in PKE.
El Stalowa Wola					Privatization process failed. The Treasury is considering including it into PKE.
BOT group			8,000		In Mar 2003, a group called BOT was created based on three power plants: Belchatow, Opole and Turow, as well as two lignite mines in Belchatow and Turow. According to Treasury plant, the group might be augmented by adding to it some power distributors. After the consolidation process is concluded, the group is planned to be privatized on the bourse at the turn of 2006.
PKE		30%	5,052 (power) 2,542 (heat)		As of Nov. 2004,the Polish Treasury considers including in PKE the power plant in Stalowa Wola and CHPs in Bytom, Tychy and Zabrze. Moreover, the Treasury considers creating the Polish Power Concern Polski Concern Energetyczny on the basis of PKE and some power distributors (L-6 or K-7). It might be privatized in 2006. As of Nov. 2004, the Treasury holds more than 85% in PKE.

Source: www.securities.com

13.2.2 Bulgaria

During the first decade after 1989, the privatization process in Bulgaria was quite slow, with state-ownership transferred only for some groups of small hydro-power plants. In its 1997 Opinion, the European Commission concluded that Bulgaria needed to step up considerably its efforts in the energy sector in order to prepare for integration, particularly in the following areas: the adjustment of monopolies, access to networks, energy pricing, emergency preparedness, development of energy efficiency and, restructuring and privatization. In response to the recommendations issued in the report of the EC, the government issued a restructuring program which cited energy as one of the five priority sectors in which swift privatization was planned to take place by 2005. The sale of new groups of hydro-power plants would be supplemented with selling coal extraction servicing companies, thermal plants, enterprises separated from Kozloduy and power and heating distributors.

However, during the following two years, little progress was recorded in the privatization of TPPs and power and heating distribution companies. In August 2003, most of the estimated EUR 95 million total revenues from the privatization in the energy sector since mid-2001, had been

generated by sales of small-sized HPPs (sold at a total price of EUR 54 million) and of some of the mining companies (Beli Breg, Choukourovo, Stanyantsi etc.), sold for a total of approximately EUR 28 million. Contrary to the provisions of the restructuring program announced in 2001, the privatization procedure for the thermal producers and the electricity and heat distributors had not yet been launched.

However, the process picked up during the second half of 2003, when the government launched the privatization procedure for the seven electricity distribution companies. The power operators were grouped in three packages of which 67% shares were offered for sale. The process was successfully finalized in August 2003, with total receipts from the sale of the stakes offered in the companies reaching EUR 693.2mn, amount that exceeded the best-case estimates of the government by nearly 50%. The remaining 33% state-owned stake in the power retailers will not be offered for sale till 2009. The winning bidders were EVN of Austria, CEZ of the Czech Republic and German E.ON.

Table 45. Privatization Bids for the 3 Groups of Electricity Distributors in Bulgaria (EUR million)

	Western Group (Sofia city, Sofia district, Pleven)	**Southeast Group** (Plovdiv, Stara Zagora)	**Northeast Group** (Varna, Gorna Oriahovitsa)
EVN (Austria)	302.0	**271.0***	-
CEZ (the Czech Republic)	**281.5***	171.5	121.5
Enel (Italy)	241.2	201.0	120.6
E.ON (Germany)	270.5	-	**140.7***
PPC (Greece)	165.0	180.0	80.0

* - Winning bids

Source: www.securities.com

Still in 2004, the government selected a consultant for organizing tenders for the TPPs in Varna and Bobov Dol, as well as the combined district heating supplier and power producer in Rousse. The Russian company Gazprom, the Italian Enel, as well as all new owners of the retail power distributors have pledged to participate in the tenders.

Furthermore, in the same year, the privatisation agency launched tenders for full stakes in 8 debt-ridden district heating companies in Lovech, Bourgas, Pleven and Gabrovo, as well as a 98% stake in the heating firm in Veliko Tarnovo.

13.2.3 The Czech Republic

The government's attempt to sell its 67.60 % stake in CEZ along with stakes in the eight regional distributors failed in 2001 when none of the short-listed bidders (including the company generally regarded as the leading bidder, Electricite de France) was willing to pay the suggested price of CZK 200 bn.

The government returned to the drawing board and decided to attempt the sale again, but first, it would merge CEZ with the country's eight regional distributors. In return, CEZ was to sell its majority stake in the electricity transmission system operator (CEPS) to the Czech National Property Fund (FNM) subsidiary Osinek and the Labor and Social Services Ministry.

The government's plan was modified by the Czech Anti-Monopoly Office (UOHS), which ruled that the merger could go ahead only if CEZ subsequently sold one of the five distributors in which it acquired a majority and the three in which it acquired minority stakes.

The transfer of stakes took place in April 2003.

13.3 Limitations in Comparability between Transactions in the Selected CEE Countries and the Future Privatization of TEC

The brief overview of the energy markets in the selected CEE Countries (Poland, Bulgaria and the Czech Republic) serves to substantiate some important limitations in the comparability between the privatization deals in these countries and a similar transaction in Romania.

Such limitations stem from: the particularities of the electricity market model in place in each of these countries at the moment when the selected comparable transactions occurred, the transition periods negotiated by such countries for environmental compliance with EU norms, as well as the structure of the companies privatized.

More precisely, the countries where comparables were selected from had a "single buyer" model in place at the time when most privatizations (including the ones selected for purposes of this valuation) took place. Under this market model, power generators had the possibility to conclude PPAs with state-owned entities, which guaranteed a steady stream of revenues for long periods of time (+10 years). The constant selling price factored into such PPAs was sufficiently elevated to ensure that all costs (operating expenses, debt service, investment requirements, environmental costs etc.) incurred by the privatized electricity producers would be covered. A PPA is a significant incentive for an investor and, where present, it can change dramatically the transaction value in the privatization of a power generator as compared to the same transaction without PPA. Romania has adopted the "third party access" market model in which PPAs with a state-owned entity cannot be concluded.

At the same time, countries like Poland and Bulgaria have negotiated longer transition periods for compliance with EU environmental standards which eases considerably the constraints on the investment plan of a potential investor acquiring a power generator in such countries. Moreover, Poland negotiated with the EU the possibility to grant public aid to some of its polluters to support their efforts to reach compliance with EU norms in this field.

Finally, most of the transactions selected as similar with and relevant for the privatization of TEC involved power generators that did not have mining operations incorporated into a complex, which can also limitations to comparability.